

2005 ANNUAL REPORT

# Cabot Oil & Gas Corporation

Long-Term Inventory

Long-Life Resources

Low Associated Geological Risk

Large Scale Developments

Focused Exploration

Expanding Reserve Base

Cabot Oil & Gas Corporation, headquartered in Houston, Texas, is a leading North American exploration and production independent. The company's reserves are focused in both conventional & unconventional basins including the East, the West (Rocky Mountain and Mid-Continent), the Gulf Coast (South and East Texas to North Louisiana) and in Canada.

## Financial Highlights

	Year Ended December 31,		
	2003	2004	2005
<b>Financial Data</b> <i>(In millions, except share amounts)</i>			
Operating Revenues	\$ 509.4	\$ 530.4	\$ <b>682.8</b>
Net income	\$ 21.1	\$ 88.4	\$ <b>148.4</b>
Per Share <sup>(1)</sup>	\$ 0.44	\$ 1.81	\$ <b>3.04</b>
Discretionary Cash Flow <sup>(2)</sup>	\$ 266.4	\$ 294.3	\$ <b>374.4</b>
Per Share <sup>(1)</sup>	\$ 5.54	\$ 6.04	\$ <b>7.66</b>
Capital and Exploration Expenditures	\$ 188.2	\$ 259.5	\$ <b>425.6</b>
Common Dividends per Share	\$ 0.16	\$ 0.16	\$ <b>0.16</b>
Average Common Shares Outstanding <i>(In thousands)</i>	48,074	48,733	<b>48,856</b>
<b>Capitalization</b> <i>(In millions)</i>			
Long-Term Debt	\$ 270.0	\$ 250.0	\$ <b>320.0</b>
Shareholders' Equity <i>(Successful Efforts Method)</i>	\$ 365.2	\$ 455.7	\$ <b>600.2</b>
<b>Annual Production Volume</b>			
Bcfe	89.0	84.8	<b>84.4</b>
% Growth	(2%)	(5%)	<b>(1%)</b>
% Gas	81%	86%	<b>88%</b>
<b>Proved Reserves</b> <sup>(3)</sup>			
Natural Gas <i>(Bcf)</i>	1,069.5	1,134.1	<b>1,262.1</b>
Oil, Condensate and Natural Gas Liquids <i>(Mmbbl)</i>	12.1	11.4	<b>11.5</b>
Total Proved <i>(Bcfe)</i>	1,142.1	1,202.4	<b>1,330.9</b>
Total Developed <i>(Bcfe)</i>	868.7	909.7	<b>999.7</b>
% Gas	94%	94%	<b>95%</b>
% Developed	76%	76%	<b>75%</b>
Reserve Life <i>(Years)</i>	12.8	14.2	<b>15.8</b>
<b>Reserve Additions</b>			
Drilling Additions <i>(Bcfe)</i>	115.8	147.4	<b>187.9</b>
Drilling Additions, Revisions and Purchases <i>(Bcfe)</i>	113.1	146.2	<b>212.9</b>
Reserve Replacement %	127%	172%	<b>252%</b>
Reserve Replacement Costs - Additions <i>(\$ per Mcfe)</i>	\$ 1.41	\$ 1.63	\$ <b>1.77</b>
Reserve Replacement Cost - Additions, Revisions and Purchases <i>(\$ per Mcfe)</i>	\$ 1.46	\$ 1.67	\$ <b>1.91</b>
<b>Wells Drilled</b>			
Total Gross	173	256	<b>316</b>
Total Net	132.0	219.8	<b>247.1</b>
Gross Success Rate %	89%	95%	<b>95%</b>
<b>Produced Average Natural Gas Sales Price</b> <i>(\$ per Mcf)</i>			
Gulf Coast	\$ 4.78	\$ 5.27	\$ <b>6.38</b>
West	\$ 3.67	\$ 4.75	\$ <b>6.00</b>
East	\$ 5.15	\$ 5.60	\$ <b>8.02</b>
Canada		\$ 4.69	\$ <b>6.79</b>
Total Company	\$ 4.51	\$ 5.20	\$ <b>6.74</b>
<b>Crude and Condensate Price</b> <i>(\$ per Bbl)</i>	\$ 29.55	\$ 31.55	\$ <b>44.19</b>

(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 92 of this report for details.

## To Our Shareholders

This past year Cabot again established new benchmarks for many of the value driving metrics including net income, cash flow from operations, discretionary cash flow and total proved reserves. The financial results were driven by a robust commodity price environment that kept improving throughout the year. Net income for the year was \$148.4 million, 68 percent over the prior year. Cash flow from operations totaled \$364.6 million, while discretionary cash flow was \$374.4 million. These cash flow figures exceed last year's record by 34 and 27 percent, respectively.

Total proved reserves reached 1,330.9 Bcfe, the highest level ever, on the strength of a 95 percent successful drilling program during the year. Through the drillbit and from better well performance, the Company added 193 Bcfe to its reserve base. In addition, as a result of a strategic initiative to build **Long-Term Inventory**, Cabot commenced an active program to increase ownership in existing fields. We were successful in two of these endeavors adding 20 Bcfe of proved reserves to our base, both of which provide many opportunities to enhance value and afford Cabot the ability to control its own destiny.

With the strength of commodity prices over the last several years has come increased pressure on the cost to conduct operations. Our investment program yielded these reserves at a very competitive \$1.91 per Mcfe. This unit cost is attractive based on the level of investment made, including the leasing of 439 thousand acres in new areas, and the competitive dynamics within the industry.

On the production front, we were successful in growing production in three of our four producing regions on the strength of a portfolio of **Long-Life Resources**. Overall Cabot's production profile was essentially flat at 84.4 Bcfe. The East region grew 10 percent on the strength of an expanded drilling program that was 100 percent successful. Our West region, which includes the Mid-Continent area and the Rocky Mountain basins, returned

to a growth profile for the first time in seven years growing over six percent, driven by a highly successful development drilling program. In Canada, where we have a grass roots effort, our strategy paid dividends with six successful wells that produced our first measurable level of production. The Gulf Coast region production experienced a decline driven by the nature of the basin, hurricane disruptions and our continuing focus on transitioning this region's drilling program toward a more repeatable strategy with **Low Associated Geological Risk**. Cabot's strategy is defined by those characteristics that are expressed on the front cover of this report, and which are further described in detail along with their impact to Cabot later in this report.

In 2005, Cabot experienced our first ever stock split. The 3-for-2 exchange on March 31, 2005 also provided to you, our shareholder, the first ever dividend increase. The stock approached its pre-split price before a mild winter took its toll on the entire sector. We considered this softening an opportunity and repurchased over 400,000 shares of our common stock investing over \$19 million.

The acquisitions, which totaled \$73 million and the stock repurchase program were largely funded through borrowings on our credit facility. In spite of this, Cabot ended the year with a 36 percent capitalization ratio, one of the best in its history.

### Looking Ahead

2005 was another milestone year, not so much for the financial results but for the fact that we moved closer to our ultimate goal of positioning Cabot to grow both reserves and production in each of our operating regions, year after year. Our strategic direction has been to move the Company toward emphasizing **Large Scale Developments** of reserves through drilling and **Focused Exploration** opportunities that will generate development inventory to continue the cycle.

2006 will be no different. We have our largest drilling program planned for the year focused predominantly on development of existing leasehold, including the acreage acquired in late 2005. Our exploration and exploitation efforts in Canada, the Paradox Basin, north Louisiana and in our East region shale plays all provide repeatable drilling opportunities with success. Details of these efforts follow this report.

Presently, we have many positive actions occurring in each of our regions, many of which have yet to be included in our valuation. I believe Cabot has successfully transitioned away from its dependence on higher risk, steeper decline prospects in south Louisiana and offshore. As a matter of fact, we have no exploratory wells scheduled in our 2006 program in these areas.

For 2006, we will continue to build on the success of each region's **Expanding Reserve Base** and the Company's success at stabilizing overall produc-

tion. Combine this with an expanding drilling program and operationally you have the ground work for growth in 2006. Additionally, we continue to lease acreage on new play concepts which we have not yet discussed for competitive reasons.

Cabot delivered in 2005 a 55 percent total shareholder return; however, I

strongly believe this return is only partial recognition of the value we truly created. I believe in 2006, with our continued execution of this strategic direction, we will see recognition of further value creation. I want to thank you for your support, and thank each employee who has worked diligently to deliver these very positive results. With what I see in Cabot's

portfolio for 2006, I look forward to our discussion next year.

Sincerely,



Dan O. Dinges  
*Chairman, President  
and Chief Executive Officer*



# Long-Term Inventory

Cabot at the time of this publication can boast of 8,470 – 9,250 undrilled locations in its portfolio. Assuming 400 wells drilled per year, simple math says it’s an average 22 year inventory. Figure 1 indicates the portfolio of locations by region.

- The East region is the dominant force in this equation, with 593 proved undeveloped locations and 4,357 probable and possible locations spread across approximately one million acres Cabot has in its possession. Combine that with 2,724 possible infill locations and you have a total potential of 7,674 locations with over 2 Tcf of potential resource.
- The Company has approximately 700 thousand acres across its West region, with 60 percent undeveloped. Through continued advances in technology, the demand for the natural gas in North America and the level of commodity prices, Cabot is positioned to accelerate its drilling activity.
- In the Gulf Coast, Cabot has successfully leased large blocks of acreage from major exploration and production companies and timber companies to build its drilling inventory. This process started in 2002 and has gradually expanded. Today, this region has exposure in resource type plays throughout the Gulf Coast region as well as traditional Gulf Coast exploration plays.

Figure 1.

Region	2005 Year-end Proved Reserves (Bcfe)	Future Drilling Locations
East	637.4	7,500-8,000
West	432.3	500-700
Gulf Coast	240.9	450-500
Canada	20.3	20-50
<b>Total</b>	<b>1,330.9</b>	<b>8,470-9,250</b>



# Long-Life Resources

At the end of 2005, Cabot’s reserve life index totaled 15.8 years based on its total proved reserve portfolio.

- The East region by its nature is the leading contributor to the long-life resource base. Quantity of opportunity is what drives this play. The current rate of proved developed producing reserves is 21 years and the total proved rate is 30 years.
- The Gulf Coast region has been migrating away from steep decline wells to a more moderate portfolio of longer life resource wells. This shift is expected to extend the region’s reserve life and provide more opportunity for growth.

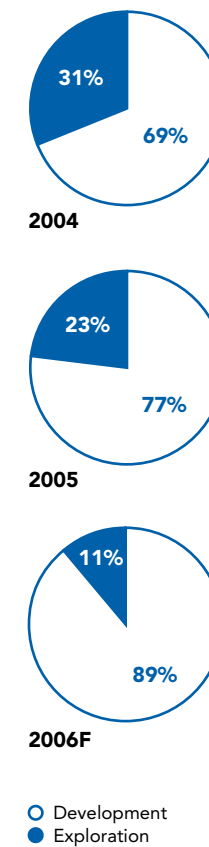




# Low Associated Geological Risk

Cabot has been transitioning the focus of its drilling portfolio in the direction of large scale acreage developments across its regions. For 2006, the Company has continued to lower its exploration exposure as highlighted by the graphs shown in Figure 2. The nature of this change relates directly to an expanded resource inventory across all regions that Cabot can now draw on.

**Figure 2.**  
**Drilling Spending**



- The East region has had four consecutive years of expanding development drilling programs – the last two of which have combined for 356 wells, with a 99 percent rate of success. Over the past five years, Cabot's success rate is 97 percent in the East.
- The greatest effort in this transition has been the Company's concentration in its Gulf Coast region. The Gulf Coast has expanded its operation to a repeatable, lower risk drilling predictability of the program, through continued investment in east and south Texas and north Louisiana. Currently there are no wildcat wells forecast to drill in south Louisiana or offshore.
- In Canada, the Company has focused in the Musreau area where it has had success and now is looking at potential down spacing. Additionally, we look forward to the development of our recent successes at the Narraway, Boltan and Hinton discoveries.



# Large Scale Developments

With opportunities in the industry harder to find, companies with scalable development programs are of significant interest due to the mitigation of reinvestment risk.

- For 2006, the East region program is again expanded to 240 wells with a plan for 2007 of 300 wells. This scale of program is possible only with continued investment in such projects as the Henlawson pipeline project which created 10 Mmcfe per day of additional production capacity.
- In the Greater Green River Basin of southwestern Wyoming, Cabot has an active development program in the Moxa Arch with 18 gross wells planned for 2006. Based on the Company's extensive acreage position (187,000 gross / 104,000 net acres), we plan to initiate a down-spacing program for the proven Frontier and Dakota reservoirs, resulting in an additional 700 locations on eighty-acre spacing.
- The Wind Dancer project, in the Greater Green River Basin of southwestern Wyoming, had nine producing wells in the play at the end of 2005. The plan is to initiate a forty-acre infill pilot program in March of 2006, utilizing single pad technology that could result in up to 48 additional development locations.
- The Gulf Coast Minden prospect originated this past summer through a large acreage acquisition from a major oil company, and Cabot now controls 7,000 acres over the area. The Company is pleased with the initial results and will remain active in this area throughout 2006. On forty-acre spacing, this prospect has the potential for 175 plus locations.
- In Canada, Cabot continues to pursue a farm in strategy to significantly increase its acreage position in deep basin gas areas and build on its success in the Musreau, Boltan, Narraway and Hinton areas.

As stated publicly, the Company is investing in four areas that once the acreage is leased, all lead to large scale developments that will carry Cabot for years to come.





# Focused Exploration

The Company has not abandoned its exploration effort but has instead, refined it to require prospects to have a certain level of development potential after the initial discovery. Several of Cabot's more immediate exploration and exploitation projects are highlighted below.



- The East region initiated a horizontal drilling program in 2005 to accelerate exploitation of its acreage. The region also drilled 83 wells to deeper shale horizons and commenced leasing on three new shale prospects.
- In the Paradox Basin, the West region shot 40 square miles of 3-D and 26 linear miles of 2-D seismic. An additional 22 square miles of 3-D seismic and six wells are planned for this basin in 2006. These projects could provide multiple offset drilling opportunities.
- In north Louisiana, Cabot has two 3-D seismic surveys at various stages of completion. One survey is over the Eros prospect, and the other is over Clear Branch. These surveys combined cover 20,250 acres and the 3-D will dictate activity levels for years to come. Additionally, the Gulf Coast region has commenced the drilling of its Castor prospect which covers 9,200 acres and, if successful, will lead to many new locations.
- The Canadian region has had significant success in its Hinton, Narraway and Boltan discoveries. Cabot has plans for additional exploration projects at Kiskiu and Raven, in 2006. The Company has considerable acreage in each of these areas that will allow for follow-up development drilling upon successful completion of these exploration wells.



By successfully transitioning to Cabot's strengths, the Company has become a company with a continually **Expanding Reserve Base** positioned to grow for years to come. Each region has a profile of activity that independently is attractive; add it up and you have a resource opportunity that many covet. This will continue to bring value to Cabot's shareholders.



**TOP:** Fracture stimulation on Amherst 18H well, West Virginia

**LEFT:** Nitrogen-foam fracture stimulation on Amherst 18H

**RIGHT:** Bonham Compressor Station, West Virginia

# Board of Directors

## Directors

### **Dan O. Dinges**

*Chairman, President and  
Chief Executive Officer*

### **Robert F. Bailey**

*Former President and Chief Executive Officer,  
TransRepublic Resources, Inc.*

### **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, Houston Exploration Company*

### **Robert L. Keiser**

*Former Chairman of the Board, Oryx Energy  
Company (now Kerr-McGee Corporation)*

### **Robert Kelley**

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

### **C. Wayne Nance**

*Former President, Tenneco Oil Company*

### **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 F. Bailey  
Robert Kelley  
P. Dexter Peacock

### **Compensation Committee**

#### **William P. Vititoe - Chairman**

John G. L. Cabot  
James G. Floyd  
Robert Kelley

### **Executive Committee**

#### **P. Dexter Peacock - Chairman**

John G. L. Cabot  
Dan O. Dinges  
C. Wayne Nance

### **Corporate Governance and Nominations Committee**

#### **James G. Floyd - Chairman**

C. Wayne Nance  
P. Dexter Peacock  
William P. Vititoe

### **Safety and Environmental Affairs Committee**

#### **Robert F. Bailey - Chairman**

James G. Floyd  
William P. Vititoe



## IN MEMORIAM

### **Scott Butler**

1954 – 2005

In December 2005, we were saddened by the loss of a close associate and good friend. Scott spent seven years with us, most recent as Vice President, Regional Manager for our West operations. He was an instrumental part of the Company's management team. Scott's leadership, industry knowledge and personal demeanor have been, and will continue to be, missed.

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, 2005**

Commission file number **1-10447**

**CABOT OIL & GAS CORPORATION**

(Exact name of registrant as specified in its charter)

**Delaware**

(State or other jurisdiction of  
incorporation or organization)

**04-3072771**

(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
<b>Common Stock, par value \$.10 per share</b>	<b>New York Stock Exchange</b>
<b>Rights to Purchase Preferred Stock</b>	<b>New York Stock Exchange</b>

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

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 ☒

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 ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 ☒ 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 ☒

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, 2005), as of the last business day of registrant's most recently completed second fiscal quarter was approximately \$1.7 billion.

As of January 31, 2006, there were 48,610,408 shares of Common Stock outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 4, 2006 are incorporated by reference into Part III of this report.

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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. 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. 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.

## PART I

### ITEM 1. BUSINESS

#### OVERVIEW

Cabot Oil & Gas is an independent oil and gas company engaged in the exploration, development, acquisition and exploitation of oil and gas properties located in North America. The five principal areas of operation are Appalachian Basin, Rocky Mountains, Anadarko Basin, onshore and offshore the Texas and Louisiana Gulf Coast, and the 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 2005 of \$148.4 million, or \$3.04 per share, exceeded the prior year's net income of \$88.4 million or \$1.81 per share, by \$60.0 million, or \$1.23 per share. The per share data for 2004 has been adjusted for the 3-for-2 split of our stock that occurred in March 2005. The year-over-year net income increase was achieved due to higher natural gas and crude oil production revenues, primarily as a result of higher commodity prices, partially offset by higher operating expenses and taxes. Operating Revenues increased by \$152.4 million or 29% due to strong commodity prices. Natural gas production revenues increased by \$119.5 million over the prior year. Crude oil and condensate revenues and brokered natural gas revenues also increased by \$14.2 million and \$22.3 million, respectively. Partially offsetting these increased revenues, operating expenses increased by \$54.5 million between 2005 and 2004. This increase was principally due to increased exploration costs, brokered natural gas costs and taxes other than income. Net income in 2005 was also reduced by an increase in income tax expense of \$37.6 million. At December 31, 2005, our debt-to-total-capital ratio was 36%, down slightly from 37% at the end of 2004.

Natural gas production increased to 73.9 Bcf in 2005 from 72.8 Bcf in 2004. This growth resulted from our 2004 and 2005 drilling programs, which focused on natural gas projects, especially in the East. On an equivalent basis, our production level in 2005 was down slightly from 2004. We produced 84.4 Bcfe, or 231.1 Mmcfe per day, in 2005, as compared to 84.8 Bcfe, or 232.3 Mmcfe per day, in 2004. The growth in natural gas production was offset by the natural decline in oil production in south Louisiana, as well as the impact of the 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.

In 2005, energy commodity prices remained strong throughout the year. Our 2005 realized natural gas price was \$6.74 per Mcf, compared to a 2004 price of \$5.20. Our realized crude oil price was \$44.19 per Bbl, compared to a 2004 price of \$31.55. These realized prices include the realized impact of derivative instruments. This strong price environment allowed us to pursue our largest organic capital program ever while still maintaining our financial flexibility. In the current year, this flexibility allowed us the ability to acquire additional interests in two fields in the Gulf Coast. We believe that as a result of our strong capital program and financial flexibility, we should be able to continue to take advantage of additional attractive acquisition opportunities that may arise.

A portion of our production was covered by oil and gas hedge instruments throughout 2005 to cover production in 2005 and 2006. At December 31, 2005, 33% and 26% of our natural gas and crude oil anticipated production, respectively, are hedged for 2006 through the use of derivatives that qualify for hedge accounting. As of December 31, 2005, no derivatives are in place for 2007. Our decision to hedge 2006 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. Our average hedged prices on natural gas and crude oil for 2006 anticipated production are expected to be higher than comparable prices realized in 2005.

For the year ended December 31, 2005, we drilled 316 gross wells with a success rate of 95% compared to 256 gross wells with a success rate of 95% for the prior year. In 2006, we plan to drill approximately 391 gross wells.

Our proved reserves totaled approximately 1,331 Bcfe at December 31, 2005, of which 95% was natural gas. This reserve level was up by 11% from 1,202 Bcfe at December 31, 2004 on the strength of results from our drilling program and the increase in our capital spending.

Our 2005 capital and exploration spending was \$425.6 million, including \$73.1 million, primarily in the Gulf Coast, to acquire proved producing properties, compared to \$259.5 million of total capital and exploration spending in 2004. We remain focused on our strategies of balancing our capital investments between acceptable risk and strongest economics, along with balancing longer life investments with impact exploration opportunities. In the past, we have used a portion of the cash flow from our long-lived East and Mid-Continent natural gas reserves to fund our exploration and development efforts in the Gulf Coast and Rocky Mountains areas. We have continued that practice, and the allocation of capital among regions in 2005 was similar in percentage to the allocation in 2004, with the Gulf Coast region being

allocated an additional 12% in capital over the previous year. In 2006, we plan to spend approximately \$396 million which includes a layer of investment for new projects or property acquisitions that may arise during the year.

In March 2005, we completed a 3-for-2 split of our common stock in the form of a stock distribution. All common stock accounts and per share data have been retroactively adjusted to give effect to the 3-for-2 split of our common stock.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. See “Forward-Looking Information” for further details.

The following table presents certain reserve, production and well information as of December 31, 2005.

	East	West			Gulf Coast	Canada	Total
		Rocky Mountains	Mid-Continent	Total			
Proved Reserves at Year End (Bcfe) _____							
Developed _____	448.4	189.5	169.3	358.8	172.9	19.6	<b>999.7</b>
Undeveloped _____	189.0	51.7	21.8	73.5	68.0	0.7	<b>331.2</b>
<b>Total</b>	<b>637.4</b>	<b>241.2</b>	<b>191.1</b>	<b>432.3</b>	<b>240.9</b>	<b>20.3</b>	<b>1,330.9</b>
Average Daily Production (Mmcfe per day) _____	59.2	37.3	29.1	66.4	102.1	3.4	<b>231.1</b>
Reserve Life Index (In years) <sup>(1)</sup> _____	29.5	17.7	18.0	17.8	6.5	16.2	<b>15.8</b>
Gross Wells _____	2,745	576	680	1,256	788	20	<b>4,809</b>
Net Wells <sup>(2)</sup> _____	2,550.2	252.4	471.8	724.2	515.7	3.9	<b>3,794.0</b>
Percent Wells Operated (Gross) _____	96.8%	51.2%	76.9%	65.1%	73.9%	40.0%	<b>84.5%</b>

(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.

## 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 were \$99.0 million, or 23% of our total 2005 capital spending, and \$75.2 million, or 29% of our total 2004 capital spending. For 2006, we have budgeted \$116.1 million for capital and exploration expenditures in the region.

At December 31, 2005, we had 2,745 wells (2,550.2 net), of which 2,657 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea and Devonian Shale formations at depths primarily ranging from 1,000 to 9,500 feet. Average net daily production in 2005 was 59.2 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, 2005, we had 637.4 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 48% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2005, we drilled 185 wells (179.8 net) in the East region, of which 182 wells (176.8 net) were development and extension wells. In 2006, we plan to drill approximately 239 wells.

In 2005, we produced and marketed approximately 70 barrels of crude oil/condensate per day in the East region at market responsive prices.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2005. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC). 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. 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 under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately 2% of East production is sold on fixed price contracts that typically renew annually.

## **WEST REGION**

Our activities in the West region are managed by a regional office in Denver, Colorado. At December 31, 2005, we had 432.3 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, Washakie and Big Horn Basins in Wyoming and Paradox Basin in Colorado. At December 31, 2005, we had 241.2 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 \$45.4 million for 2005, or 11% of our total capital and exploration expenditures, and \$41.5 million for 2004. For 2006, we have budgeted \$57.8 million for capital and exploration expenditures in the area.

We had 576 wells (252.4 net) in the Rocky Mountains area as of December 31, 2005, of which 295 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 5,500 to 15,000 feet. Average net daily production in the Rocky Mountains during 2005 was 37.3 Mmcfe.

In 2005, we drilled 49 wells (16.1 net) in the Rocky Mountains, of which 45 wells (13.3 net) were development wells. In 2006, we plan to drill 42 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 \$23.7 million for 2005, or 6% of our total 2005 capital and exploration expenditures, and \$12.1 million for 2004. For 2006, we have budgeted \$33.1 million for capital and exploration expenditures in the area.

As of December 31, 2005, we had 680 wells (471.8 net) in the Mid-Continent area, of which 523 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Chase, Morrow, Red Fork and Chester formations at depths ranging from 2,200 to 10,000 feet. Average net daily production in 2005 was 29.1 Mmcfe. At December 31, 2005, we had 191.1 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, or 14% of our total proved reserves.

In 2005, we drilled 34 wells (21.5 net) in the Mid-Continent, all of which were development and extension wells. In 2006, we plan to drill 42 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 2% 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 2005, we produced and marketed approximately 450 barrels of crude oil/condensate per day in the West region at market responsive prices.

## **GULF COAST REGION**

Our exploration, development and production activities in the Gulf Coast region are primarily concentrated in north and south Louisiana, south Texas and, to a lesser extent, the Gulf of Mexico. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley, Hosston, Miocene and Frio age formations in Louisiana and the Frio, Vicksburg and Wilcox formations in Texas at depths ranging from 3,000 to 25,000 feet. Capital and exploration expenditures were \$233.5 million for 2005, or 55% of our total capital and exploration expenditures, and \$112.6 million for 2004. During 2005, we spent \$72.1 million on proved property acquisitions. For 2006, we have budgeted \$154.4 million of our total budget for capital and exploration expenditures in the region. Our 2006 Gulf Coast drilling program will emphasize activity in our focus areas of east Texas, north Louisiana and south Texas.

In 2005, we drilled 39 wells (26.2 net) in the Gulf Coast region, of which 23 wells (17.4 net) were development wells. In 2006, we plan to drill 55 wells. We had 788 wells (515.7 net) in the Gulf Coast region as of December 31, 2005, of which 582 wells are operated by us. Average daily production in 2005 was 102.1 Mmcfe, compared to 115.3 Mmcfe in 2004. The decline is the result of lower production from our properties in south Louisiana, offset partially by increased production from the coastal Texas area. At December 31, 2005, we had 240.9 Bcfe of proved reserves (80% natural gas) in the Gulf Coast region, which represented 18% 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 2005, we produced and marketed approximately 4,100 barrels of crude oil/condensate per day in the Gulf Coast 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, 2005, we had 20.3 Bcfe of proved reserves (97% natural gas) in the Canada region, constituting 2% of our total proved reserves.

Capital and exploration expenditures in Canada were \$22.9 million for 2005, or 5% of our total capital and exploration expenditures, and \$16.2 million for 2004. For 2006, we have budgeted \$30.7 million for capital and exploration expenditures in the area.

We had 20 wells (3.9 net) in the Canada region as of December 31, 2005, of which 8 wells are operated by us. Principal producing intervals in the Canada region are in the Falher, Bluesky, Cadomin and the Swan Hills formations at depths ranging from 9,500 to 16,000 feet. Average net daily production in Canada during 2005 was 3.4 Mmcfe.

In 2005, we drilled 9 wells (3.5 net) in Canada, of which 5 wells (1.7 net) were development and extension wells. In 2006, we plan to drill 13 wells.

In 2005, we produced and marketed approximately 50 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 2005 we primarily employed natural gas and crude oil price swap and collar agreements to attempt to manage price risk more effectively. 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. 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.

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, 2005.

	Natural Gas (Mmcf)			Liquids <sup>(1)</sup> (Mbbbl)			Total <sup>(2)</sup> (Mmcfe)		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
East _____	445,964	188,976	634,940	403	—	403	448,379	188,976	<b>637,355</b>
Rocky Mountains _____	179,730	49,629	229,359	1,631	344	1,975	189,514	51,696	<b>241,210</b>
Mid-Continent _____	163,815	21,563	185,378	913	41	954	169,295	21,811	<b>191,106</b>
Gulf Coast _____	136,417	56,344	192,761	6,077	1,943	8,020	172,882	67,999	<b>240,881</b>
Canada _____	18,971	687	19,658	103	8	111	19,591	731	<b>20,322</b>
<b>Total</b>	<b>944,897</b>	<b>317,199</b>	<b>1,262,096</b>	<b>9,127</b>	<b>2,336</b>	<b>11,463</b>	<b>999,661</b>	<b>331,213</b>	<b>1,330,874</b>

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

(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 1) we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues, 2) we used appropriate engineering, geologic and evaluation principles in making our estimates and projections and 3) 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 2005, we filed estimates of our oil and gas reserves for the year 2004 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 2005. If we had considered the impact of our hedging activities 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 (Mbbbl)	Total (Mmcf) <sup>(1)</sup>
<b>December 31, 2002</b>	<b>1,060,959</b>	<b>18,393</b>	<b>1,171,316</b>
Revision of Prior Estimates	(6,122)	307	(4,278)
Extensions, Discoveries and Other Additions	105,497	1,723	115,835
Production	(71,906)	(2,846)	(88,976)
Purchases of Reserves in Place	1,590	—	1,591
Sales of Reserves in Place	(20,534)	(5,474)	(53,380)
<b>December 31, 2003</b>	<b>1,069,484</b>	<b>12,103</b>	<b>1,142,108</b>
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)
<b>December 31, 2004</b>	<b>1,134,081</b>	<b>11,384</b>	<b>1,202,383</b>
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)
<b>December 31, 2005</b>	<b>1,262,096</b>	<b>11,463</b>	<b>1,330,874</b>
<b>Proved Developed Reserves</b>			
December 31, 2002	819,412	13,267	899,016
December 31, 2003	812,280	9,405	868,712
December 31, 2004	857,834	8,652	909,747
<b>December 31, 2005</b>	<b>944,897</b>	<b>9,127</b>	<b>999,661</b>

(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.

### 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,		
	2005	2004	2003
<b>Net Wellhead Sales Volume</b>			
Natural Gas (Bcf)			
Gulf Coast	28.1	31.3	30.0
West	23.2	21.9	23.8
East	21.4	19.4	18.6
Canada	1.2	0.2	—
Crude/Condensate/Ngl (Mbbbl)			
Gulf Coast	1,530	1,809	2,625
West	172	163	193
East	27	27	27
Canada	18	3	—
<b>Produced Natural Gas Sales Price (\$/Mcf) <sup>(1)</sup></b>			
Gulf Coast	\$ 6.38	\$ 5.27	\$ 4.78
West	6.00	4.75	3.67
East	8.02	5.60	5.15
Canada	6.79	4.69	—
Weighted Average	6.74	5.20	4.51
<b>Crude/Condensate Sales Price (\$/Bbl) <sup>(1)</sup></b>			
	\$ 44.19	\$ 31.55	\$ 29.55
<b>Production Costs (\$/Mcfe) <sup>(2)</sup></b>			
	\$ 1.23	\$ 0.99	\$ 0.87

(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.

### Leasehold Acreage by State

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkansas _____	1,981	425	0	0	1,981	425
Colorado _____	16,268	14,053	208,597	131,490	224,865	145,543
Kansas _____	29,067	27,745	0	0	29,067	27,745
Louisiana _____	67,324	43,186	182,211	151,840	249,535	195,026
Montana _____	397	210	14,102	10,835	14,499	11,045
New York _____	2,956	1,105	10,642	5,683	13,598	6,788
Ohio _____	6,247	2,384	1,625	436	7,872	2,820
Oklahoma _____	173,208	120,257	15,407	11,110	188,615	131,367
Pennsylvania _____	112,522	63,986	108	43	112,630	64,029
Texas _____	109,837	75,737	83,540	67,690	193,377	143,427
Utah _____	1,740	529	180,257	96,425	181,997	96,954
Virginia _____	22,298	20,201	2,642	1,558	24,940	21,759
West Virginia _____	582,411	549,728	206,725	192,171	789,136	741,899
Wyoming _____	141,317	73,074	297,342	171,176	438,659	244,250
<b>Total</b>	<b>1,267,573</b>	<b>992,620</b>	<b>1,203,198</b>	<b>840,457</b>	<b>2,470,771</b>	<b>1,833,077</b>

### 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
Louisiana _____	628	276	0	0	628	276
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 _____	27	27	754	327	781	354
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
<b>Total</b>	<b>133,191</b>	<b>112,239</b>	<b>64,793</b>	<b>52,412</b>	<b>197,984</b>	<b>164,651</b>
<b>Aggregate Total</b>	<b>1,400,764</b>	<b>1,104,859</b>	<b>1,267,991</b>	<b>892,869</b>	<b>2,668,755</b>	<b>1,997,728</b>

### Canada Leasehold Acreage by Province

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta _____	5,760	1,910	38,472	9,128	44,232	11,038
British Columbia _____	700	280	11,988	4,731	12,688	5,011
Saskatchewan _____	0	0	9,903	9,903	9,903	9,903
<b>Total</b>	<b>6,460</b>	<b>2,190</b>	<b>60,363</b>	<b>23,762</b>	<b>66,823</b>	<b>25,952</b>

### Total Net Acreage by Region of Operation

	Developed	Undeveloped	Total
East _____	735,233	251,451	986,684
West _____	277,246	422,015	699,261
Gulf Coast _____	92,380	219,403	311,783
Canada _____	2,190	23,762	25,952
<b>Total</b>	<b>1,107,049</b>	<b>916,631</b>	<b>2,023,680</b>

### 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, 2005. The figures below assume no future successful development or renewal of undeveloped acreage.

	2006	2007	2008
East _____	12,407	55,451	43,732
West _____	69,180	67,322	152,744
Gulf Coast _____	13,168	65,559	89,485
Canada _____	3,118	14,155	224
<b>Total</b>	<b>97,873</b>	<b>202,487</b>	<b>286,185</b>

### Well Summary

The following table presents our ownership at December 31, 2005, in productive natural gas and oil wells in the East region (consisting of various fields located in West Virginia, Virginia and Ohio), in the West region (consisting of various fields located in Oklahoma, Kansas, Colorado and Wyoming), in the Gulf Coast region (consisting primarily of various fields located in Louisiana and Texas) and in the Canada region (consisting of various fields located in the Provinces of Alberta and British Columbia). This summary includes natural gas and oil wells in which we have a working interest.

	Natural Gas		Oil		Total <sup>(1)</sup>	
	Gross	Net	Gross	Net	Gross	Net
East _____	2,720	2,538.2	25	12.0	2,745	2,550.2
West _____	1,201	690.5	55	33.7	1,256	724.2
Gulf Coast _____	622	375.0	166	140.7	788	515.7
Canada _____	20	3.9	0	0.0	20	3.9
<b>Total</b>	<b>4,563</b>	<b>3,607.6</b>	<b>246</b>	<b>186.4</b>	<b>4,809</b>	<b>3,794.0</b>

(1) Total does not include service wells of 73 (65.3 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, 2005										
	East		West		Gulf Coast		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful _____	182	176.8	75	32.6	19	13.7	5	1.6	281	224.7
Dry _____	0	0.0	3	1.8	0	0.0	0	0.0	3	1.8
Extension Wells										
Successful _____	0	0.0	1	0.4	3	2.7	0	0.0	4	3.1
Dry _____	0	0.0	0	0.0	1	1.0	0	0.0	1	1.0
Exploratory Wells										
Successful _____	3	3.0	1	0.7	10	6.0	1	0.7	15	10.4
Dry _____	0	0.0	3	2.1	6	2.8	3	1.2	12	6.1
<b>Total</b>	<b>185</b>	<b>179.8</b>	<b>83</b>	<b>37.6</b>	<b>39</b>	<b>26.2</b>	<b>9</b>	<b>3.5</b>	<b>316</b>	<b>247.1</b>
Wells Acquired _____	0	0.0	0	0.0	16	2.8	0	0.0	16	2.8
Wells in Progress at End of Year _____	3	3.0	3	2.0	5	3.0	3	1.1	14	9.1

## Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery records, affect competition. We believe that our extensive acreage position, existing natural gas gathering and pipeline systems and storage fields enhance our competitive position over other producers in the East region 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 each of 2005, 2004 and 2003, 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 ratable 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 developed rules governing the relationship of the pipelines with their marketing affiliates, and 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, 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 pipeline facilities within the next ten years, and at least every seven years thereafter. In addition, beginning in early 2006, 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. We are not able to predict with certainty the final outcome of this rulemaking proposal.

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. The second of these required reviews commenced in July 2005, where the FERC proposed to continue use of the indexing methodology for a further five year period.

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 the final outcome 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.

**Outer Continental Shelf Lands Act.** The federal Outer Continental Shelf Lands Act (OCSLA) and regulations promulgated pursuant thereto impose a variety of regulations relating to safety and environmental protection applicable to lessees, permit holders and other parties operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to the Outer Continental Shelf Lands Act can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or citizen prosecution. We believe that we substantially comply with the OCSLA and its regulations.

**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 (FWPCA or 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, 2005, Cabot Oil & Gas had 354 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](http://www.cabotog.com), our annual report 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. Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at [www.sec.gov](http://www.sec.gov) that contains reports filed by the Company.

## **Corporate Governance Matters**

The Company’s Corporate Governance Guidelines, 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](http://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 2005, 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 may 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.

***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, geophysics, 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 three regions in which we operate. The estimation of reserves in the Gulf Coast region requires more estimates than 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.

We are continually identifying and evaluating 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, 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, 2005, we owned or operated approximately 3,400 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 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 2005 we primarily employed natural gas and crude oil price swap and collar agreements to attempt to manage price risk. 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. 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.

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.

### ***Wyoming Royalty Litigation***

In January 2002, we were sued by 13 overriding royalty owners in Wyoming federal district court, as reported in previous filings. The plaintiffs made claims pertaining to deductions from their overriding royalty and claims concerning penalties for improper reporting. As a result of several decisions by the Court favorable to us, the case was settled in

September 2005 with no payment from us and a dismissal with prejudice of all claims by plaintiffs. The settlement included provisions for reporting and payment going forward. In the third quarter of 2005, management reversed the reserve we had recorded regarding this case, which did not have a material impact on our consolidated financial statements.

#### ***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 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 has postponed the trial date from April 17, 2006, in light of a case pending before the West Virginia Supreme Court of Appeals which may decide issues of law that may apply to the issue of deductibility of post-production expenses. We intend to challenge the class certification order by filing a Petition for Writ of Prohibition with the West Virginia Supreme Court of Appeals.

We are vigorously defending the case. We have established a reserve that management believes is adequate based on their 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 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, 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 are allowed to amend pleadings or add additional parties to the litigation. Due to the abatement of the case, we have not had the opportunity to conduct discovery in this matter. We estimate that production revenue from this field since Cody Energy, LLC acquired title is approximately \$15.7 million, and that the carrying value of this property is approximately \$33.6 million.

Although the investigation into this claim continues, we intend to vigorously defend the case. Should we receive an adverse ruling in this case, an impairment review would be assessed to determine whether the carrying value of the property is recoverable. Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, we have not established a reserve for this matter.

#### ***Raymondville Area***

In April 2004, our 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 have filed a counter claim against the Company, and one of the defendants has 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 3% 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. The defendant has filed a Motion for Reconsideration and Opposition to Proposed Order. The Court has not yet made a decision on these two motions.

### **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 \$10.2 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 2005.

### **EXECUTIVE OFFICERS OF THE REGISTRANT**

The following table shows certain information about our executive officers as of February 17, 2006, 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	52	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	57	Senior Vice President, Exploration and Production	1998
Scott C. Schroeder	43	Vice President and Chief Financial Officer	1997
J. Scott Arnold	52	Vice President, Land and Associate General Counsel	1998
Robert G. Drake	58	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	59	Vice President, Human Resources	1998
Jeffrey W. Hutton	50	Vice President, Marketing	1995
Thomas S. Liberatore	49	Vice President, Regional Manager, East Region	2003
Lisa A. Machesney	50	Vice President, Managing Counsel and Corporate Secretary	1995
Henry C. Smyth	59	Vice President, Controller and Treasurer	1998

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

**Dan O. Dinges** joined Cabot Oil & Gas Corporation as President and Chief Operating Officer and as a member of the Board of Directors in September 2001. He was promoted to his current position of Chairman, President and Chief Executive Officer in May 2002. Mr. Dinges came to Cabot after a 20-year career with Samedan Oil Corporation, a subsidiary of Noble Affiliates, Inc. The last three years, Mr. Dinges served as Samedan's Senior Vice President, as well as Division General Manager for the Offshore Division, a position he held since August 1996. He also served as a member of the Executive Operating Committee for Samedan. Mr. Dinges started his career as a Landman for Mobil Oil Corporation covering Louisiana, Arkansas and the central Gulf of Mexico. After four years of expanding responsibilities at Mobil, he joined Samedan as a Division Landman – Offshore. Over the years, Mr. Dinges held positions of increasing

responsibility at Samedan including Division Manager, Vice President and ultimately Senior Vice President. Mr. Dinges received his B.B.A. degree in Petroleum Land Management from The University of Texas.

**Thomas S. Liberatore** joined Cabot in January 2002 as Regional Manager, East and was promoted to his current position in July 2003. Prior to joining the Company, Mr. Liberatore served as Vice President, Exploration and Production for North Coast Energy. He began his career as a geologist and has held various positions of increasing responsibility for Presidio Oil Company and Belden & Blake Corporation. Mr. Liberatore received his B.S. in Geology from West Virginia University.

## 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. 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	Cash Dividends
<b>2005</b>			
First Quarter _____	<b>\$ 38.04</b>	<b>\$ 27.78</b>	<b>\$ 0.027</b>
Second Quarter _____	<b>38.13</b>	<b>28.29</b>	<b>0.040</b>
Third Quarter _____	<b>50.81</b>	<b>36.05</b>	<b>0.040</b>
Fourth Quarter _____	<b>51.54</b>	<b>40.48</b>	<b>0.040</b>
<b>2004</b>			
First Quarter _____	\$ 21.93	\$ 19.17	\$ 0.027
Second Quarter _____	28.20	20.09	0.027
Third Quarter _____	30.05	25.87	0.027
Fourth Quarter _____	32.25	27.27	0.027

As of January 31, 2006, there were 632 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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2005	—	\$ —	—	1,918,750
November 2005	207,400	\$ 43.10	207,400	1,711,350
December 2005	225,200	\$ 42.95	225,200	1,486,150
<b>Total</b>	<b>432,600</b>	<b>\$ 43.02</b>		

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. All purchases executed have been through open market transactions. There is no expiration date associated with the authorization to repurchase our securities.

## 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, and the Consolidated Financial Statements and related Notes.

		Year Ended December 31,				
		2005	2004	2003	2002	2001
<i>(In thousands, except per share amounts)</i>						
<b>Statement of Operations Data</b>						
Operating Revenues	\$	682,797	\$ 530,408	\$ 509,391	\$ 353,756	\$ 447,042
Impairment of Oil and Gas Properties <sup>(1)</sup>		—	3,458	93,796	2,720	6,852
Income from Operations		258,731	160,653	66,587	49,088	95,366
Net Income		148,445	88,378	21,132	16,103	47,084
<b>Basic Earnings per Share</b> <sup>(2)(3)</sup>						
	\$	3.04	\$ 1.81	\$ 0.44	\$ 0.34	\$ 1.04
<b>Dividends per Common Share</b> <sup>(2)</sup>						
	\$	0.147	\$ 0.107	\$ 0.107	\$ 0.107	\$ 0.107
<b>Balance Sheet Data</b>						
Properties and Equipment, Net	\$	1,238,055	\$ 994,081	\$ 895,955	\$ 971,754	\$ 981,338
Total Assets		1,495,370	1,210,956	1,055,056	1,100,947	\$ 1,092,810
Current Portion of Long-Term Debt		20,000	20,000	—	—	—
Long-Term Debt		320,000	250,000	270,000	365,000	\$ 393,000
Stockholders' Equity		600,211	455,662	365,197	350,657	\$ 346,552

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

(2) 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.

(3) 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 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 exploration and exploitation, 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 exploration, development, acquisition, exploitation, 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 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.

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 2004 and 2005, the futures market reported unprecedented natural gas and crude oil contract prices. Our realized natural gas and crude oil price was \$6.74 per Mcf and \$44.19 per Bbl, respectively, in 2005. 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 and swaps. These financial instruments are an element of our risk management strategy but prevented us from realizing the full impact of the price environment.

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 2004 and 2005. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2004" and "2005" 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:

(In \$ per Mcf)

**Natural Gas Prices by Month – 2005**

	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
<b>2005_____</b>	<b>\$ 5.78</b>	<b>\$ 5.84</b>	<b>\$ 5.52</b>	<b>\$ 6.28</b>	<b>\$ 6.19</b>	<b>\$ 5.55</b>	<b>\$ 6.05</b>	<b>\$ 6.58</b>	<b>\$ 7.76</b>	<b>\$ 8.94</b>	<b>\$ 8.53</b>	<b>\$ 7.78</b>

(In \$ per Mcf)

**Natural Gas Prices by Month – 2004**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index_____	\$ 6.15	\$ 5.77	\$ 5.15	\$ 5.37	\$ 5.94	\$ 6.68	\$ 6.14	\$ 6.04	\$ 5.08	\$ 5.79	\$ 7.63	\$ 7.78
<b>2004_____</b>	<b>\$ 5.23</b>	<b>\$ 5.23</b>	<b>\$ 5.17</b>	<b>\$ 4.88</b>	<b>\$ 4.96</b>	<b>\$ 5.23</b>	<b>\$ 5.39</b>	<b>\$ 5.21</b>	<b>\$ 4.54</b>	<b>\$ 5.29</b>	<b>\$ 5.63</b>	<b>\$ 5.55</b>

Prices for crude oil have followed a similar path as the commodity price continued to maintain strength in 2004 and rose further in 2005. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2004 and 2005. The “2004” and “2005” price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative arrangements:

(In \$ per Mcf)		Crude Oil Prices by Month – 2005											
		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
<b>2005</b>		<b>\$ 38.18</b>	<b>\$ 40.57</b>	<b>\$ 47.30</b>	<b>\$ 44.95</b>	<b>\$ 41.88</b>	<b>\$ 44.58</b>	<b>\$ 46.24</b>	<b>\$ 46.62</b>	<b>\$ 45.05</b>	<b>\$ 45.92</b>	<b>\$ 45.59</b>	<b>\$ 43.70</b>

(In \$ per Mcf)		Crude Oil Prices by Month – 2004											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index		\$ 34.23	\$ 34.50	\$ 36.72	\$ 36.62	\$ 40.28	\$ 38.05	\$ 40.81	\$ 44.88	\$ 45.94	\$ 53.09	\$ 48.48	\$ 43.26
<b>2004</b>		<b>\$ 30.62</b>	<b>\$ 30.66</b>	<b>\$ 31.62</b>	<b>\$ 30.97</b>	<b>\$ 30.80</b>	<b>\$ 31.51</b>	<b>\$ 31.43</b>	<b>\$ 33.00</b>	<b>\$ 31.61</b>	<b>\$ 32.87</b>	<b>\$ 33.15</b>	<b>\$ 30.46</b>

We reported earnings of \$3.04 per share, or \$148.4 million, for 2005. This is up from the \$1.81 per share, or \$88.4 million, reported in 2004. The stronger price environment was a primary contributor to the earnings increase due to the increase in natural gas and oil revenues. Prices, including the realized impact of derivative instruments, rose 30% for natural gas and 40% for oil.

We drilled 316 gross wells with a success rate of 95% in 2005 compared to 256 gross wells with a 95% success rate in 2004. Total capital and exploration expenditures increased by \$166.1 million to \$425.6 million, of which \$73.1 million was for property acquisitions, in 2005 compared to \$259.5 million for 2004. We believe our operating cash flow in 2006 will be sufficient to fund our capital and exploration budgeted spending of approximately \$396 million and again provide excess cash flow. Any excess cash flow may be used for acquisitions, to pay current debt due, repurchase common stock, expand our capital program or other opportunities.

Our 2006 strategy will remain consistent with 2005. We will remain focused on our strategies of balancing our capital investments between higher risk projects with the potential for higher returns and lower risk projects with more stable returns, along with balancing longer life investments with impact exploration opportunities. 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 source of cash in 2005 was from funds generated from operations, as well as borrowings on our revolving credit facility 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 subject to seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have 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, purchase treasury stock and pay dividends. Proceeds from the exercise of stock options under stock option plans during 2005 partially offset our repurchase of 452,300 treasury shares of common stock at a weighted average purchase price of \$42.41. See below for additional discussion and analysis of cash flow.

(In thousands)	Year-Ended December 31,		
	2005	2004	2003
Cash Flows Provided by Operating Activities	\$ 364,560	\$ 273,022	\$ 241,638
Cash Flows Used by Investing Activities	(412,150)	(255,357)	(151,856)
Cash Flows Provided / (Used) by Financing Activities	48,190	(8,363)	(90,660)
Net Increase / (Decrease) in Cash and Cash Equivalents	\$ 600	\$ 9,302	\$ (878)

**Operating Activities.** Net cash provided by operating activities in 2005 increased \$91.5 million over 2004. This increase is primarily due to higher commodity prices. Key components impacting net operating cash flows are 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. While we believe 2006 commodity production may exceed 2005 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 2004 increased \$31.4 million over 2003. This increase is primarily due to higher commodity prices. Key components of net operating cash flows are commodity prices, production volumes and operating costs. Average realized natural gas prices increased 15% over 2003, while crude oil realized prices increased 7% over the same period. Production volumes declined, with a 5% reduction of equivalent production in 2004 compared to 2003. 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 by investing activities are capital spending and exploration expense. We establish 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 increased for the years ended December 31, 2005 and 2004 in the amounts of \$156.8 million and \$103.5 million, respectively. The increase from 2004 to 2005 is 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. The increase from 2003 to 2004 was also primarily due to an increase in drilling activity in response to higher commodity prices. This increase largely occurred in our East region and the Rocky Mountains area of our West region. Our initial drilling activity in Canada also contributed to the increase.

**Financing Activities.** Cash flows provided by financing activities were \$48.2 million for the year ended December 31, 2005, resulting from borrowings under the credit facility, partially offset by the purchase of treasury stock and dividend payments. Cash flows used by financing activities for the year ended December 31, 2004 were \$8.4 million. This is the result of proceeds from the exercise of stock options, offset by the purchase of treasury shares and dividend payments. Cash flows used by financing activities for the year ended December 31, 2003 were \$90.7 million. This is substantially due to a net repayment on our revolving credit facility in the amount of \$95.0 million. Cash utilized for the repayments was generated from operating cash flows.

At December 31, 2005, we had \$90 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 has been adjusted to three million shares. During 2005, we repurchased 452,300 shares of our common stock at a weighted average price of \$42.41. 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, 2005 was 1,486,150. 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:

(In millions)	December 31,	
	2005	2004
Debt <sup>(1)</sup>	\$ 340.0	\$ 270.0
Stockholders' Equity	600.2	455.7
Total Capitalization	\$ 940.2	\$ 725.7
Debt to Capitalization	36%	37%
Cash and Cash Equivalents	\$ 10.6	\$ 10.0

(1) Includes \$20.0 million of current portion of long-term debt at both December 31, 2005 and 2004. Includes \$90 million of borrowings under our revolving credit facility at December 31, 2005. There were no borrowings under our revolving credit facility at December 31, 2004.

For the year ended December 31, 2005, we paid dividends of \$7.2 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.

## 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, 2005.

(In millions)	2005	2004	2003
Capital Expenditures			
Drilling and Facilities	\$ 249.3	\$ 174.0	\$ 102.0
Leasehold Acquisitions	22.1	18.3	14.1
Pipeline and Gathering	17.9	13.5	10.6
Other	1.4	1.6	1.8
	290.7	207.4	128.5
Proved Property Acquisitions	73.1	4.0	1.5
Exploration Expense	61.8	48.1	58.2
<b>Total</b>	<b>\$ 425.6</b>	<b>\$ 259.5</b>	<b>\$ 188.2</b>

We plan to drill about 391 gross wells in 2006 compared with 316 gross wells drilled in 2005. This 2006 drilling program includes approximately \$396 million in total capital and exploration expenditures, down from \$425.6 million in 2005. Capital and exploration expenditures in 2005 included a layer of \$73.1 million in proved property acquisitions as shown in the table above. 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 rate. These include reserve additions and revisions, development costs, impairments and changes in anticipated production in a future period. In 2006 management expects an increase in our depreciation, depletion and amortization rate due to negative reserve revisions and higher capital costs. This change may result in an increase of depreciation, depletion and amortization of 10% to 15% greater than 2005 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, and we have not guaranteed the debt of any other party.

A summary of our known contractual obligations as of December 31, 2005 are set forth in the following table:

(In thousands)	Total	Payments Due by Year			
		2006	2007 to 2008	2009 to 2010	2011 & Beyond
Long-Term Debt <sup>(1)</sup>	<b>\$ 340,000</b>	\$ 20,000	\$ 40,000	\$ 110,000	\$ 170,000
Interest on Long-Term Debt <sup>(2)</sup>	<b>132,960</b>	24,632	44,950	32,673	30,705
Firm Gas Transportation Agreements <sup>(3)</sup>	<b>93,766</b>	11,661	19,839	6,762	55,504
Drilling Rig Commitments <sup>(3)</sup>	<b>104,315</b>	26,055	68,585	9,675	—
Operating Leases	<b>17,746</b>	4,876	9,174	3,696	—
<b>Total Contractual Cash Obligations</b>	<b>\$ 688,787</b>	<b>\$ 87,224</b>	<b>\$ 182,548</b>	<b>\$ 162,806</b>	<b>\$ 256,209</b>

(1) Including current portion. At December 31, 2005, we had \$90 million of outstanding debt on 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 \$250 million long-term debt outstanding at December 31, 2005. Interest payments on the \$90 million of outstanding borrowings on our revolving credit facility were calculated by assuming that the December 31, 2005 outstanding balance of \$90 million will be outstanding through the 2009 maturity date and by assuming a constant interest rate of 7.25% which was the December 31, 2005 interest rate. Actual results will likely differ from these estimates and assumptions.

(3) For further information on our obligations under firm gas transportation agreements and drilling rig commitments, 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, 2005 is \$43.0 million.

Subsequent to December 31, 2005, we entered into an agreement for one additional drilling rig in the Gulf Coast. The total commitment over the next four years is \$27.4 million, of which \$0.8 million, \$9.1 million, \$9.1 million and \$8.4 million will be paid out during the years 2006, 2007, 2008 and 2009, respectively.

#### 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, geophysics, engineering and production data. The extent, quality and reliability of this technical data can vary. The degree of uncertainty varies among the three regions in which we operate. The estimation of reserves in the Gulf Coast region requires more estimates than 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 depreciation, depletion and amortization expense (DD&A) 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 DD&A.

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 2003, we significantly revised the estimated cash flow utilized in our impairment review of the Kurten field due to a loss of a reversionary interest in the field. In December 2003, our remaining interest in the field was sold. For additional discussion on the Kurten field impairment see Note 2 of the Notes to the Consolidated Financial Statements. In 2004 and 2005, there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test.

Costs attributable to our unproved properties are not subject to the impairment analysis described above; however, a portion of the costs associated with such properties is subject to amortization based on past experience and average property lives. Average property lives are determined on a regional basis and based on the estimated life of unproved property leasehold rights. Historically, the average property lives in each of the regions have not significantly changed. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately \$2.7 million or decrease by approximately \$1.6 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 Gulf Coast, East and West regions have been four, seven and seven years, respectively. Average property lives in Canada are estimated to be six 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. Any portion of the gains or losses that are considered ineffective under the SFAS No. 133 test are recorded immediately as a component of Operating Revenue, either in Natural Gas Production or Crude Oil and Condensate Revenue, on the 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 5.48% annualized for 2005, and the Citigroup Pension Liability Index, which was 5.55% for 2005. 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 5.5% at December 31, 2005 is reasonable.

In order to value our pension liabilities, we use the RP-2000 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 prior years' 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 4% 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, 2005, the assumed rate of increase was 9.0%. The net periodic cost of pension benefits included in expense also is affected by the expected long-term rate of return on plan assets assumption. The expected return on plan assets rate is normally changed less frequently than the assumed discount rate, and reflects long-term expectations, rather than current fluctuations in market conditions. The actual rate of return on plan assets may differ from the expected rate due to the volatility normally experienced in capital markets. Management's goal is to manage the investments over the long term to achieve optimal returns with an acceptable level of risk and volatility.

We have established objectives regarding plan assets in the pension plan. In our pension calculations, we have used 8% as the expected long-term return on plan assets for 2005, 2004 and 2003. However, we expect to achieve a minimum 5% annual real rate of return on the total portfolio over the long term. We believe that this is a reasonable estimate based on our actual results. The actual rate of return on plan assets annualized over the past ten years is approximately 10%.

We generally target a portfolio of assets that are within a range of approximately 60% 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.

### ***Stock-Based Compensation***

Prior to the issuance of SFAS No. 123(R) "Share Based Payment (revised 2004)", there were two alternative methods that could be used to account for stock-based compensation. The first method is the Intrinsic Value method and recognizes 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. The second method is the Fair Value method. 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. As of December 31, 2005, we account for stock-based compensation in accordance with the Intrinsic Value method. SFAS No. 123(R) requires that the fair value of stock options and any other equity-based compensation must be expensed at the grant date. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. We currently expense performance share awards; however, beginning in the first quarter of 2006, we will be required to expense all stock-based compensation. Further discussion of SFAS No. 123(R) and stock compensation is included in "Recently Issued Accounting Pronouncements."

On October 26, 2005, the Compensation Committee of our Board of Directors 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 April 2006 and April 2007, respectively. 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 is expected to reduce 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 can not 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, 2005, 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.

**Limited Partnership.** As part of the 2001 Cody acquisition, we acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. We had approximately a 25% interest in the field, including a one percent interest in the partnership. Under the partnership agreement, we had the right to a reversionary working interest that would bring our ultimate interest to 50% upon the limited partner reaching payout. Based on the addition of this reversionary interest, and because the field has over a 40-year reserve life, approximately \$91 million was allocated to this field under purchase accounting at the time of the acquisition. Additionally, the limited partner had the sole option to trigger a liquidation of the partnership.

Effective February 13, 2003, liquidation of the partnership commenced at the election of the limited partner. The limited partner was a financial entity and not an industry operator. Their decision to liquidate was based upon their perception that the value of their investment in the partnership had increased due to an increase in underlying commodity prices, primarily oil, since their investment in 1999. We proceeded with the liquidation to avoid having a minority interest in a non-operated water flood field for which the new operator was not designated at the time of liquidation. In connection with the liquidation, an appraisal was required to be obtained to allocate the interest in the partnership assets. Additionally, we were required to test the field for recoverability in accordance with SFAS No. 144. Pursuant to the terms of the partnership agreement and based on the appraised value of the partnership assets it was not possible for us to obtain the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partner's decision and our decision to proceed with the liquidation, an impairment review was performed which required an impairment charge in the first quarter of 2003 of \$87.9 million (\$54.4 million after-tax). This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact our cash flows.

**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 collar and swap arrangements to reduce the impact of declining prices on our revenue. Under both arrangements, there is also risk that the movement of the index prices will result in the Company not being able to realize the full benefit of a market improvement.

#### **Recently Issued Accounting Pronouncements**

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 47, "Accounting for Conditional Asset Retirement Obligations." This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in SFAS No. 143, "Accounting for Asset Retirement Obligations." A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the Company. FIN No. 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This Interpretation is intended to provide more information about long-lived assets, more information about future cash outflows for these obligations and more consistent recognition of these liabilities. FIN No. 47 is effective for fiscal years ending after December 15, 2005. Our financial position, results of operations and cash flows were not impacted by this Interpretation, since we currently record all asset retirement obligations.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 "Accounting for Suspended Well Costs." This staff position amends FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies who use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. For our disclosures, refer to Note 2 of the Notes to the Consolidated Financial Statements.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections-A replacement of APB Opinion No. 20 and FASB Statement No. 3." In order to enhance financial reporting consistency between periods, SFAS No. 154 modifies the requirements for the accounting and reporting of the direct effects of changes in accounting principles. Under APB Opinion No. 20, the cumulative effect of voluntary changes in accounting principle was recognized in Net Income in the period of the change. Unlike the treatment previously prescribed by APB Opinion No. 20, retrospective application is now required, unless it is not practical to determine the specific effects in each period or the cumulative effect. If the period specific effects cannot be determined, it is required that the new accounting principle must be retrospectively applied in the earliest period possible to the balance sheet accounts and a corresponding adjustment be made to the opening balance of retained earnings or another equity account. If the cumulative effect cannot be determined, it is necessary to apply the new accounting principles prospectively at the earliest practical date. If it is not feasible to retrospectively apply the change in principle, the reason that this is not possible and the method used to report the change is required to be disclosed. The statement also provides that changes in accounting for depreciation, depletion or amortization should be treated as changes in accounting estimate inseparable from a change in accounting principle and that disclosure of the preferability of the change is required. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005.

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment." SFAS No. 123(R) revises SFAS No. 123, "Accounting for Stock-Based Compensation," and focuses on accounting for share-based payments for services provided by employee to employer. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model, and either a binomial or Black-Scholes model may be used. During the first quarter of 2005, the Securities and Exchange Commission (SEC) approved a new rule for public companies to delay the adoption of this standard. In April 2005, the SEC took further action to amend Regulation S-X to state that the provisions of SFAS No. 123(R) will be

effective beginning with the first annual or interim reporting period of the registrant's first fiscal year beginning on or after June 15, 2005 for all non-small business issuers. As a result, we will not adopt this SFAS until the first quarter of 2006. We plan to use the modified prospective application method as detailed in SFAS No. 123(R). At this time, management does not believe that the adoption of SFAS No. 123(R) will materially impact our operating results, nor will there be any impact on our future cash flows. See "Stock-Based Compensation" below for further information.

In October 2005, the FASB issued FSP FAS 123(R)-2, "Practical Accommodation to the Application of Grant Date as defined in FASB Statement No. 123(R)." This FSP provides guidance on the definition and practical application of "grant date" as described in SFAS No. 123(R). The grant date is described as the date that the employee and employer have met a mutual understanding of the key terms and conditions of an award. The other elements of the definition of grant date are: 1) the award must be authorized, 2) the employer must be obligated to transfer assets or distribute equity instruments so long as the employee has provided the necessary service and 3) the employee is affected by changes in the company's stock price. To determine the grant date, we are allowed to use the date the award is approved in accordance with our corporate governance requirements so long as the three elements described above are met. Furthermore, the recipient cannot negotiate the award's terms and conditions with the employer and the key terms and conditions of the award are communicated to all recipients within a reasonably short time period from the approval date. We will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

In November 2005, the FASB issued FSP FAS 123(R)-3 "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," which provides a simpler, more practical transition election relating to the calculation of the "APIC pool." The APIC pool is defined as the pool of excess tax benefits available to absorb tax deficiencies occurring after the adoption of SFAS No. 123(R). Under this FSP, companies can elect to perform simpler computations to derive the beginning balance of the APIC pool as well as the impact on the APIC pool of fully vested and outstanding awards as of the SFAS No. 123(R) adoption date. The beginning balance can be computed by taking the sum of all tax benefits incurred prior to the adoption of SFAS No. 123(R) from stock-based compensation plans less the tax effected (using a blended statutory rate) pro forma stock-based compensation cost. In addition, increases to the APIC pool for fully vested awards can be calculated by multiplying the tax rate times the tax benefit of the deduction. The calculation of any awards that are partially vested or granted after the SFAS No. 123(R) adoption date will not be affected by this FSP and will be calculated in accordance with SFAS No. 123(R) which requires that only the excess tax benefit or deficiency of the tax deduction over the tax effect of the compensation cost recognized should be considered for the APIC pool. Also under the FSP, all tax benefits recognized on fully vested awards and the excess tax benefits for partially vested and new awards will be reported on the Statement of Cash Flows as a component of financing activities. Companies will have up to one year after adopting SFAS No. 123(R) to decide to elect and disclose whether they plan to use the alternative method or the original method prescribed in SFAS No. 123(R) for the calculation of the APIC pool. We will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

In February 2006, the FASB issued FSP FAS 123(R)-4, "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement upon the Occurrence of a Contingent Event." Within certain share-based payment plans, a company can be required to settle outstanding options upon the occurrence of certain events, such as a change in control or liquidity of a company or the death or disability of the shareholder. This FSP amends paragraphs 32 and A229 of SFAS No. 123(R) to incorporate a probability assessment by a company. Under SFAS No. 123(R), it is required that options and similar instruments be classified as liabilities if the entity can be required under any circumstances to settle the instrument in cash or other assets. Under the FSP, a cash settlement feature that can be exercised only upon the occurrence of a contingent event that is outside of the employee's control does not meet the criteria for liability classification, and should remain to be classified in equity, unless it becomes probable that the contingent event will occur. The effective date for the guidance in this FSP is upon the initial adoption of SFAS No. 123(R). We will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

## 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

### 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 the Natural Gas Production Revenues line item in the Statement of Operations.

	Year Ended December 31,		Variance	
	2005	2004	Amount	Percent
Natural Gas Production (Mmcf)				
Gulf Coast	28,071	31,358	(3,287)	(10%)
West	23,224	21,866	1,358	6%
East	21,435	19,442	1,993	10%
Canada	1,149	167	982	588%
Total Company	73,879	72,833	1,046	1%
Natural Gas Production Sales Price (\$/Mcf)				
Gulf Coast	\$ 6.38	\$ 5.27	\$ 1.11	21%
West	\$ 6.00	\$ 4.75	\$ 1.25	26%
East	\$ 8.02	\$ 5.60	\$ 2.42	43%
Canada	\$ 6.79	\$ 4.69	\$ 2.10	45%
Total Company	\$ 6.74	\$ 5.20	\$ 1.54	30%
Natural Gas Production Revenue (In thousands)				
Gulf Coast	\$ 179,061	\$ 165,177	\$ 13,884	8%
West	139,298	103,851	35,447	34%
East	171,902	108,935	62,967	58%
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)				
Gulf Coast	\$ 31,200			
West	28,997			
East	51,798			
Canada	2,414			
Total Company	\$ 114,409			
Volume Variance Impact on Natural Gas Production Revenue (In thousands)				
Gulf Coast	\$ (17,317)			
West	6,448			
East	11,170			
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) _____	<b>\$ 9.14</b>	\$ 6.56	\$ 2.58	39%
Volume Brokered (Mmcf) _____	<b>10,793</b>	12,876	(2,083)	(16%)
Brokered Natural Gas Revenues (In thousands)	<b>\$ 98,605</b>	\$ 84,416		
Purchase Price (\$/Mcf) _____	<b>\$ 8.08</b>	\$ 5.84	\$ 2.24	38%
Volume Brokered (Mmcf) _____	<b>10,793</b>	12,876	(2,083)	(16%)
Brokered Natural Gas Cost (In thousands)	<b>\$ 87,183</b>	\$ 75,217		
Brokered Natural Gas Margin (In thousands)	<b>\$ 11,422</b>	\$ 9,199	\$ 2,223	24%
(In thousands)				
Sales Price Variance Impact on Revenue _____	<b>\$ 27,852</b>			
Volume Variance Impact on Revenue _____	<b>(13,664)</b>			
	<b>\$ 14,188</b>			
(In thousands)				
Purchase Price Variance Impact on Purchases _____	<b>\$ (24,130)</b>			
Volume Variance Impact on Purchases _____	<b>12,165</b>			
	<b>\$ (11,965)</b>			

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 the Crude Oil and Condensate Revenues line item in the Statement of Operations.

	Year Ended December 31,		Variance	
	2005	2004	Amount	Percent
Crude Oil Production (Mbbbl)				
Gulf Coast	1,528	1,805	(277)	(15%)
West	166	159	7	4%
East	27	27	—	—
Canada	18	4	14	350%
Total Company	1,739	1,995	(256)	(13%)
Crude Oil Sales Price (\$/Bbl)				
Gulf Coast	\$ 42.81	\$ 30.67	\$ 12.14	40%
West	\$ 55.37	\$ 40.29	\$ 15.08	37%
East	\$ 53.84	\$ 38.28	\$ 15.56	41%
Canada	\$ 43.39	\$ 37.93	\$ 5.46	14%
Total Company	\$ 44.19	\$ 31.55	\$ 12.64	40%
Crude Oil Revenue (In thousands)				
Gulf Coast	\$ 65,427	\$ 55,357	\$ 10,070	18%
West	9,155	6,404	2,751	43%
East	1,463	1,049	414	39%
Canada	791	129	662	513%
Total Company	\$ 76,836	\$ 62,939	\$ 13,897	22%
Price Variance Impact on Crude Oil Revenue (In thousands)				
Gulf Coast	\$ 18,547			
West	2,496			
East	423			
Canada	100			
Total Company	\$ 21,566			
Volume Variance Impact on Crude Oil Revenue (In thousands)				
Gulf Coast	\$ (8,492)			
West	299			
East	—			
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:

(In thousands)	Year Ended December 31,			
	2005		2004	
	Realized	Unrealized	Realized	Unrealized
<b>Operating Revenues - Increase/(Decrease) to Revenue</b>				
<b>Cash Flow Hedges</b>				
Natural Gas Production _____	\$ (98,223)	\$ 1,114	\$ (54,564)	\$ 137
Crude Oil _____	(2,430)	(6)	—	6
<b>Total Cash Flow Hedges</b> _____	<b>(100,653)</b>	<b>1,108</b>	(54,564)	143
<b>Other Derivative Financial Instruments</b>				
Natural Gas Production _____	—	—	(444)	777
Crude Oil _____	(14,842)	5,518	(17,908)	(2,923)
<b>Total Other Derivative Financial Instruments</b> _____	<b>(14,842)</b>	<b>5,518</b>	(18,352)	(2,146)
	<b>\$ (115,495)</b>	<b>\$ 6,626</b>	<b>\$ (72,916)</b>	<b>\$ (2,003)</b>

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. Average borrowings based on month end balances for the 2005 year were approximately \$130 million compared to approximately \$95 million in the prior year. 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.

#### **2004 and 2003 Compared**

We reported net income for the year ended December 31, 2004 of \$88.4 million, or \$1.81 per share. During 2003, we reported net income of \$21.1 million, or \$0.44 per share. Operating income increased by \$94.1 million compared to the prior year, from \$66.6 million to \$160.7 million. The increase in net income and operating income was principally due to decreased operating expenses from 2003 to 2004 related to the decrease in impairments of oil and gas properties of \$90.3 million related to the loss in 2003 of a reversionary interest in the Kurten field. In addition, the increases in operating income and net income were due to an increase in our realized natural gas and crude oil prices.

**Natural Gas Production Revenues.** Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was \$5.20 per Mcf compared to \$4.51 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instruments which reduced these prices by \$0.76 per Mcf in 2004 and \$0.68 per Mcf in 2003. The following table excludes the unrealized gain from the change in derivative fair value of \$0.9 million and the unrealized loss of \$1.5 million for the years ended December 31, 2004 and 2003, respectively. These unrealized changes in fair value have been included in the Natural Gas Production Revenues line item in the Statement of Operations.

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
<b>Natural Gas Production (Mmcf)</b>				
Gulf Coast	31,358	29,550	1,808	6%
West	21,866	23,776	(1,910)	(8%)
East	19,442	18,580	862	5%
Canada	167	—	167	—
Total Company	72,833	71,906	927	1%
<b>Natural Gas Production Sales Price (\$/Mcf)</b>				
Gulf Coast	\$ 5.27	\$ 4.78	\$ 0.49	10%
West	\$ 4.75	\$ 3.67	\$ 1.08	29%
East	\$ 5.60	\$ 5.15	\$ 0.45	9%
Canada	\$ 4.69	\$ —	\$ 4.69	—
Total Company	\$ 5.20	\$ 4.51	\$ 0.69	15%
<b>Natural Gas Production Revenue (In thousands)</b>				
Gulf Coast	\$ 165,177	\$ 141,107	\$ 24,070	17%
West	103,851	87,245	16,606	19%
East	108,935	95,672	13,263	14%
Canada	784	—	784	—
Total Company	\$ 378,747	\$ 324,024	\$ 54,723	17%
<b>Price Variance Impact on Natural Gas Production Revenue (In thousands)</b>				
Gulf Coast	\$ 15,434			
West	23,613			
East	8,828			
Canada	784			
Total Company	\$ 48,659			
<b>Volume Variance Impact on Natural Gas Production Revenue (In thousands)</b>				
Gulf Coast	\$ 8,635			
West	(7,009)			
East	4,438			
Canada	—			
Total Company	\$ 6,064			

The increase in natural gas production revenues was mainly a result of increased sales prices as well as the increase in overall production. Natural gas production was up slightly from the prior year and production revenues also increased from 2003. Natural gas production increased slightly in all regions except the West region, where the decline in production was due to lower capital spending in 2003 and continued natural decline. The increases in both sales price and production resulted in an increase in natural gas production revenues of \$54.7 million.

### Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
Sales Price (\$/Mcf) _____	\$ 6.56	\$ 5.16	\$ 1.40	27%
Volume Brokered (Mmcf) _____	12,876	18,557	(5,681)	(31%)
Brokered Natural Gas Revenues (In thousands)	\$ 84,416	\$ 95,754		
Purchase Price (\$/Mcf) _____	\$ 5.84	\$ 4.64	\$ 1.20	26%
Volume Brokered (Mmcf) _____	12,876	18,557	(5,681)	(31%)
Brokered Natural Gas Cost (In thousands)	\$ 75,217	\$ 86,104		
Brokered Natural Gas Margin (In thousands)	\$ 9,199	\$ 9,650	\$ (451)	(5%)
(In thousands)				
Sales Price Variance Impact on Revenue _____	\$ 18,026			
Volume Variance Impact on Revenue _____	(29,363)			
	\$ (11,337)			
(In thousands)				
Purchase Price Variance Impact on Purchases _____	\$ (15,451)			
Volume Variance Impact on Purchases _____	26,338			
	\$ 10,887			

The decrease in brokered natural gas revenues of \$11.3 million combined with the decline in brokered natural gas cost of \$10.9 million resulted in a decrease to the brokered natural gas margin of \$0.5 million.

### Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was \$31.55 per Bbl compared to \$29.55 per Bbl for 2003. These prices include the realized impact of derivative instruments, which reduced these prices by \$8.98 per Bbl in 2004 and \$1.41 per Bbl in 2003. The following table excludes the unrealized loss from the change in derivative fair value of \$2.9 million and \$1.9 million for the years ended December 31, 2004 and 2003, respectively. These unrealized changes in fair value have been included in the Crude Oil and Condensate Revenues line item in the Statement of Operations.

	Year Ended December 31,		Variance	
	2004	2003	Amount	Percent
<b>Crude Oil Production (Mbbbl)</b>				
Gulf Coast _____	1,805	2,591	(786)	(30%)
West _____	159	188	(29)	(15%)
East _____	27	27	—	—
Canada _____	4	—	4	—
Total Company _____	1,995	2,806	(811)	(29%)
<b>Crude Oil Sales Price (\$/Bbl)</b>				
Gulf Coast _____	\$ 30.67	\$ 29.48	\$ 1.19	4%
West _____	\$ 40.29	\$ 30.11	\$ 10.18	34%
East _____	\$ 38.28	\$ 32.65	\$ 5.63	17%
Canada _____	\$ 37.93	\$ —	\$ 37.93	—
Total Company _____	\$ 31.55	\$ 29.55	\$ 2.00	7%
<b>Crude Oil Revenue (In thousands)</b>				
Gulf Coast _____	\$ 55,357	\$ 76,375	\$ (21,018)	(28%)
West _____	6,404	5,675	729	13%
East _____	1,049	870	179	21%
Canada _____	129	—	129	—
Total Company _____	\$ 62,939	\$ 82,920	\$ (19,981)	(24%)
<b>Price Variance Impact on Crude Oil Revenue (In thousands)</b>				
Gulf Coast _____	\$ 2,151			
West _____	1,604			
East _____	179			
Canada _____	129			
Total Company _____	\$ 4,063			
<b>Volume Variance Impact on Crude Oil Revenue (In thousands)</b>				
Gulf Coast _____	\$ (23,169)			
West _____	(875)			
East _____	—			
Canada _____	—			
Total Company _____	\$ (24,044)			

The decline in crude oil production is due to emphasis on natural gas in the Gulf Coast drilling program, along with the natural decline of existing production in south Louisiana. The increase in the realized crude oil price combined with the decline in production resulted in a net revenue decrease of \$20.0 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:

(In thousands)	Year Ended December 31,			
	2004		2003	
	Realized	Unrealized	Realized	Unrealized
<b>Operating Revenues - Increase/(Decrease) to Revenue</b>				
<b>Cash Flow Hedges</b>				
Natural Gas Production	\$ (54,564)	\$ 137	\$ (48,829)	\$ (691)
Crude Oil	—	6	(2,973)	32
<b>Total Cash Flow Hedges</b>	(54,564)	143	(51,802)	(659)
<b>Other Derivative Financial Instruments</b>				
Natural Gas Production	(444)	777	—	(777)
Crude Oil	(17,908)	(2,923)	(990)	(1,911)
<b>Total Other Derivative Financial Instruments</b>	(18,352)	(2,146)	(990)	(2,688)
	<b>\$ (72,916)</b>	<b>\$ (2,003)</b>	<b>\$ (52,792)</b>	<b>\$ (3,347)</b>

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 \$3.7 million. This change was primarily a result of decreases in natural gas transportation revenue and natural gas liquid revenue for the year ended December 31, 2004.

**Operating Expenses.** Total costs and expenses from operations decreased \$85.3 million for the year ended December 31, 2004 compared to the year ended December 31, 2003. The primary reasons for this fluctuation are as follows:

- Brokered Natural Gas Cost decreased \$10.9 million. For additional information related to this decrease see the analysis performed for Brokered Natural Gas Revenue and Cost.
- Exploration expense decreased \$10.0 million primarily as a result of higher dry hole expense in 2003. During 2004, we drilled 5 dry exploratory wells compared to 15 in the corresponding period of 2003.
- Depreciation, Depletion and Amortization increased, as anticipated, by approximately 9% or \$8.4 million. The increase was primarily due to negative reserve revisions in south Louisiana in 2003, which increased the per Mcfe DD&A rate in 2004.
- Impairment of Oil and Gas Properties expense decreased \$90.3 million. This decrease is substantially related to a pre-tax non-cash impairment charge of \$87.9 million incurred in 2003 related to the loss of a reversionary interest in the Kurten field. Effective February 13, 2003, the Kurten partnership commenced liquidation at the limited partner's election. In connection with the liquidation, an appraisal was obtained to allocate the interest in the partnership assets. Based on the receipt of the appraisal in February 2003, we determined that we would not receive the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, we performed an impairment review which resulted in an \$87.9 million charge.
- General and Administrative expense increased \$9.6 million from 2003 to 2004. Stock compensation expense increased by \$4.9 million as a result of performance share awards issued in 2004 and increased amortization of restricted stock grants for grants which occurred during the year. Compliance fees related to Sarbanes-Oxley increased expenses by \$2.3 million, and there was a \$1.2 million increase in employee related expenses.
- Taxes Other Than Income increased \$3.9 million as a result of higher commodity prices realized during the year 2004 as compared to the prior year.

**Interest Expense, Net.** Interest expense decreased \$1.7 million. This variance is due to a lower average level of outstanding debt on the revolving credit facility offset somewhat by an increase in Prime rates. Average daily borrowings under the revolving credit facility during the year were \$0.5 million in 2004 which is a decrease from \$0.7 million in 2003. Our other remaining debt is at fixed interest rates.

**Income Tax Expense.** Income tax expense increased \$35.2 million due to an increase in our pre-tax net income.

## 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 10 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, 2005, we had nine cash flow hedges open: eight natural gas price collar arrangements and one crude oil price collar arrangement. At December 31, 2005, a \$20.7 million (\$12.9 million net of tax) unrealized loss was recorded to Accumulated Other Comprehensive Income, along with a \$22.4 million short-term derivative liability and a \$1.7 million short-term derivative receivable, which is shown in Other Current Assets on the Balance Sheet. 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, 2005 we would expect to reclassify to the Statement of Operations, over the next 12 months, \$12.9 million in after-tax charges associated with commodity hedges. This reclassification represents the net liability associated with open positions currently not reflected in earnings at December 31, 2005 related to anticipated 2006 production.

#### Hedges on Production - Swaps

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These derivatives are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. During 2005, natural gas price swaps covered 20,557 Mmcft, or 28% of our gas production, fixing the sales price of this gas at an average of \$5.14 per Mcft.

At December 31, 2005, we had no open natural gas price swap contracts covering 2006 production.

From time to time, we enter into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS No. 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2005, we did not have any of these types of arrangements.

#### 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 2005, natural gas price collars covered 15,157 Mmcft of our gas production, or 21% of our gas production with a weighted average floor of \$5.59 per Mcft and a weighted average ceiling of \$8.61 per Mcft. During 2005, an oil price collar covered 365 Mbbl of our crude oil production, or 21% of our crude oil production with a weighted average floor of \$40.00 per Mbbl and a weighted average ceiling of \$50.50 per Mbbl.

At December 31, 2005, we had open natural gas price collar contracts covering our 2006 production as follows:

Natural Gas Price Collars			
Contract Period	Volume in Mmcf	Weighted Average Ceiling / Floor	Net Unrealized Loss (In thousands)
<b>As of December 31, 2005</b>			
First Quarter 2006	6,702	\$12.74/\$8.25	
Second Quarter 2006	6,776	12.74/8.25	
Third Quarter 2006	6,850	12.74/8.25	
Fourth Quarter 2006	6,851	12.74/8.25	
<b>Full Year 2006</b>	<b>27,179</b>	<b>\$12.74/\$8.25</b>	<b>\$ (20,425)</b>

At December 31, 2005, we had one open crude oil price collar contract covering our 2006 production as follows:

Crude Oil Price Collar			
Contract Period	Volume in Mbbl	Weighted Average Ceiling / Floor	Net Unrealized Loss (In thousands)
<b>As of December 31, 2005</b>			
First Quarter 2006	90	\$76.00/\$50.00	
Second Quarter 2006	91	76.00/50.00	
Third Quarter 2006	92	76.00/50.00	
Fourth Quarter 2006	92	76.00/50.00	
<b>Full Year 2006</b>	<b>365</b>	<b>\$76.00/\$50.00</b>	<b>\$ (317)</b>

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

(In thousands)	December 31, 2005		December 31, 2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<b>Debt</b>				
7.19% Notes	\$ 60,000	\$ 62,938	\$ 80,000	\$ 87,770
7.26% Notes	75,000	81,713	75,000	85,849
7.36% Notes	75,000	83,990	75,000	87,111
7.46% Notes	20,000	23,083	20,000	23,804
Credit Facility	90,000	90,000	—	—
	<b>\$ 320,000</b>	<b>\$ 341,724</b>	<b>\$ 250,000</b>	<b>\$ 284,534</b>

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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### 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 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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 Note 11 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003.

#### ***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, 2005 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, 2005, 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.

A stylized, handwritten-style signature of PricewaterhouseCoopers LLP in black ink.

Houston, Texas  
March 6, 2006

## CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
	2005	2004	2003
<i>(In thousands, except per share amounts)</i>			
OPERATING REVENUES			
Natural Gas Production	\$ 499,177	\$ 379,661	\$ 322,556
Brokered Natural Gas	98,605	84,416	95,816
Crude Oil and Condensate	82,348	60,022	81,040
Other	2,667	6,309	9,979
	<b>682,797</b>	530,408	509,391
OPERATING EXPENSES			
Brokered Natural Gas Cost	87,183	75,217	86,162
Direct Operations - Field and Pipeline	61,750	53,581	50,399
Exploration	61,840	48,130	58,119
Depreciation, Depletion and Amortization	108,458	103,343	94,903
Impairment of Unproved Properties	12,966	10,145	9,348
Impairment of Oil & Gas Properties (Note 2)	—	3,458	93,796
General and Administrative	37,650	34,735	25,112
Taxes Other Than Income	54,293	41,022	37,138
	<b>424,140</b>	369,631	454,977
Gain / (Loss) on Sale of Assets	74	(124)	12,173
INCOME FROM OPERATIONS	<b>258,731</b>	160,653	66,587
Interest Expense and Other	22,497	22,029	23,545
Income Before Income Taxes and Cumulative Effect of Accounting Change	<b>236,234</b>	138,624	43,042
Income Tax Expense	87,789	50,246	15,063
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	<b>148,445</b>	88,378	27,979
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (Note 11)	—	—	(6,847)
NET INCOME	<b>\$ 148,445</b>	\$ 88,378	\$ 21,132
Basic Earnings Per Share - Before Accounting Change	\$ 3.04	\$ 1.81	\$ 0.58
Diluted Earnings Per Share - Before Accounting Change	\$ 2.99	\$ 1.79	\$ 0.58
Basic Loss Per Share - Accounting Change	\$ —	\$ —	\$ (0.14)
Diluted Loss Per Share - Accounting Change	\$ —	\$ —	\$ (0.14)
Basic Earnings Per Share	\$ 3.04	\$ 1.81	\$ 0.44
Diluted Earnings Per Share	\$ 2.99	\$ 1.79	\$ 0.44
Weighted Average Common Shares Outstanding	<b>48,856</b>	48,733	48,074
Diluted Common Shares (Note 12)	<b>49,725</b>	49,339	48,435

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

## CONSOLIDATED BALANCE SHEET

	December 31	
(In thousands, except per share amounts)	2005	2004
<b>ASSETS</b>		
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 10,626	\$ 10,026
Accounts Receivable	168,248	125,754
Inventories	24,616	24,049
Deferred Income Taxes	15,674	21,345
Other	11,148	13,505
Total Current Assets	230,312	194,679
PROPERTIES AND EQUIPMENT, NET (Successful Efforts Method)	1,238,055	994,081
Deferred Income Taxes	19,587	14,855
OTHER ASSETS	7,416	7,341
	<b>\$ 1,495,370</b>	<b>\$ 1,210,956</b>
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
CURRENT LIABILITIES		
Accounts Payable	\$ 140,006	\$ 104,969
Current Portion of Long-Term Debt	20,000	20,000
Deferred Income Taxes	941	944
Derivative Contracts	22,478	38,368
Accrued Liabilities	35,159	32,608
Total Current Liabilities	218,584	196,889
LONG-TERM DEBT	320,000	250,000
DEFERRED INCOME TAXES	289,381	247,376
OTHER LIABILITIES	67,194	61,029
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS' EQUITY		
Common Stock:		
Authorized – 80,000,000 Shares of \$.10 Par Value		
Issued – 50,081,983 Shares and 49,680,915 Shares in 2005 and 2004, respectively	5,008	4,968
Additional Paid-in Capital	397,349	380,125
Retained Earnings	252,167	110,935
Accumulated Other Comprehensive Loss	(15,115)	(20,351)
Less Treasury Stock, at Cost:		
1,513,850 and 1,061,550 Shares in 2005 and 2004, respectively	(39,198)	(20,015)
Total Stockholders' Equity	600,211	455,662
	<b>\$ 1,495,370</b>	<b>\$ 1,210,956</b>

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

## CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)	Year Ended December 31,		
	2005	2004	2003
<b>CASH FLOWS FROM OPERATING ACTIVITIES</b>			
Net Income	<b>\$ 148,445</b>	\$ 88,378	\$ 21,132
Adjustments to Reconcile Net Income to Cash			
Provided by Operating Activities:			
Cumulative Effect of Accounting Change	—	—	6,847
Depreciation, Depletion and Amortization	<b>108,458</b>	103,343	94,903
Impairment of Unproved Properties	<b>12,966</b>	10,145	9,348
Impairment of Oil & Gas Properties	—	3,458	93,796
Deferred Income Tax Expense	<b>39,628</b>	31,769	(9,837)
(Gain) / Loss on Sale of Assets	<b>(74)</b>	124	(12,173)
Exploration Expense	<b>61,840</b>	48,130	58,119
Unrealized Change in Derivative Fair Value	<b>(6,626)</b>	2,003	3,347
Performance Share Compensation	<b>3,357</b>	3,429	—
Stock-Based Compensation Expense and Other	<b>6,446</b>	3,475	885
Changes in Assets and Liabilities:			
Accounts Receivable	<b>(42,494)</b>	(39,404)	(17,397)
Inventories	<b>(567)</b>	(5,808)	(2,989)
Other Current Assets	<b>1,188</b>	3,255	(9,208)
Other Assets	<b>(192)</b>	(491)	163
Accounts Payable and Accrued Liabilities	<b>29,803</b>	17,231	7,041
Other Liabilities	<b>2,382</b>	3,985	(2,339)
Net Cash Provided by Operating Activities	<b>364,560</b>	273,022	241,638
<b>CASH FLOWS FROM INVESTING ACTIVITIES</b>			
Capital Expenditures	<b>(351,306)</b>	(207,346)	(122,018)
Proceeds from Sale of Assets	<b>996</b>	119	28,281
Exploration Expense	<b>(61,840)</b>	(48,130)	(58,119)
Net Cash Used by Investing Activities	<b>(412,150)</b>	(255,357)	(151,856)
<b>CASH FLOWS FROM FINANCING ACTIVITIES</b>			
Increase in Debt	<b>265,000</b>	187,000	248,655
Decrease in Debt	<b>(195,000)</b>	(187,000)	(341,000)
Sale of Common Stock Proceeds	<b>4,586</b>	12,474	6,728
Purchase of Treasury Stock	<b>(19,183)</b>	(15,631)	—
Dividends Paid	<b>(7,213)</b>	(5,206)	(5,043)
Net Cash Provided / (Used) by Financing Activities	<b>48,190</b>	(8,363)	(90,660)
Net Increase / (Decrease) in Cash and Cash Equivalents	<b>600</b>	9,302	(878)
Cash and Cash Equivalents, Beginning of Period	<b>10,026</b>	724	1,602
Cash and Cash Equivalents, End of Period	<b>\$ 10,626</b>	\$ 10,026	\$ 724

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

## CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

<i>(In thousands)</i>	Common Shares	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance at December 31, 2002	48,200	\$ 4,820	454	\$ (4,384)	\$ 351,486	\$ (12,939)	\$ 11,674	\$ 350,657
Net Income							21,132	21,132
Exercise of Stock Options	517	52			7,716			7,768
Cash Dividends at \$0.16 per Share							(5,043)	(5,043)
Other Comprehensive Loss						(10,196)		(10,196)
Stock Grant Vesting	90	9			870			879
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			15,034			15,113
Purchase of Treasury Stock			608	(15,631)				(15,631)
Performance Share Awards					2,394			2,394
Stock Grant Vesting	80	8			2,625			2,633
Cash Dividends at \$0.16 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	<b>148,445</b>
Exercise of Stock Options	300	30			8,217			<b>8,247</b>
Purchase of Treasury Stock			452	(19,183)				<b>(19,183)</b>
Performance Share Awards					4,147			<b>4,147</b>
Stock Grant Vesting	101	10			4,860			<b>4,870</b>
Cash Dividends at \$0.16 per Share							(7,213)	<b>(7,213)</b>
Other Comprehensive Income						5,236		<b>5,236</b>
<b>Balance at December 31, 2005</b>	<b>50,082</b>	<b>\$ 5,008</b>	<b>1,514</b>	<b>\$ (39,198)</b>	<b>\$ 397,349</b>	<b>\$ (15,115)</b>	<b>\$ 252,167</b>	<b>\$ 600,211</b>

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

## CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In thousands)	Year Ended December 31,		
	2005	2004	2003
Net Income	<b>\$ 148,445</b>	\$ 88,378	\$ 21,132
Other Comprehensive Income / (Loss)			
Reclassification Adjustment for Settled Contracts	<b>100,653</b>	53,516	47,926
Changes in Fair Value of Hedge Positions	<b>(92,559)</b>	(48,494)	(63,014)
Minimum Pension Liability	<b>(205)</b>	(1,404)	(1,333)
Foreign Currency Translation Adjustment	<b>808</b>	662	(5)
Deferred Income Tax	<b>(3,461)<sup>(1)</sup></b>	(1,496) <sup>(2)</sup>	6,230 <sup>(3)</sup>
Total Other Comprehensive Income / (Loss)	<b>5,236</b>	2,784	(10,196)
Comprehensive Income	<b>\$ 153,681</b>	\$ 91,162	\$ 10,936

(1) Deferred income tax of (\$3.5) million at December 31, 2005 represents the net deferred tax liability of approximately (\$38.4) million on the Reclassification Adjustment for Settled Contracts, approximately \$35.3 million on the Changes in Fair Value of Hedge Positions, approximately less than \$0.1 million on the Minimum Pension Liability Adjustment and approximately (\$0.3) million on the Foreign Currency Translation Adjustment.

(2) Deferred income tax of (\$1.5) million at December 31, 2004 represents the net deferred tax liability of approximately (\$20.4) million on the Reclassification Adjustment for Settled Contracts, approximately \$18.5 million on the Changes in Fair Value of Hedge Positions, approximately \$0.6 million on the Minimum Pension Liability Adjustment and (\$0.2) million on the Foreign Currency Translation Adjustment.

(3) Deferred income tax of \$6.2 million at December 31, 2003 represents the net deferred tax liability of approximately (\$18.3) million on the Reclassification Adjustment for Settled Contracts, approximately \$24.0 million on the Changes in Fair Value of Hedge Positions, approximately \$0.5 million on the Minimum Pension Liability Adjustment and approximately less than \$0.1 million on the Foreign Currency Translation Adjustment.

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 exploration, development, 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 exploration and exploitation, 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 March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 47, "Accounting for Conditional Asset Retirement Obligations." This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the Company. FIN No. 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This Interpretation is intended to provide more information about long-lived assets, more information about future cash outflows for these obligations and more consistent recognition of these liabilities. FIN No. 47 is effective for fiscal years ending after December 15, 2005. The Company's financial position, results of operations and cash flows were not impacted by this Interpretation, since all asset retirement obligations are currently recorded.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 "Accounting for Suspended Well Costs." This staff position amends FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies who use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. For the Company's disclosures, refer to Note 2 of the Notes to the Consolidated Financial Statements.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections-A replacement of APB Opinion No. 20 and FASB Statement No. 3." In order to enhance financial reporting consistency between periods, SFAS No. 154 modifies the requirements for the accounting and reporting of the direct effects of changes in accounting principles. Under APB Opinion No. 20, the cumulative effect of voluntary changes in accounting principle was recognized in Net Income in the period of the change. Unlike the treatment previously prescribed by APB Opinion No. 20, retrospective application is now required, unless it is not practical to determine the specific effects in each period or the cumulative effect. If the period specific effects cannot be determined, it is required that the new accounting principle must be retrospectively applied in the earliest period possible to the balance sheet accounts and a corresponding adjust-

ment be made to the opening balance of retained earnings or another equity account. If the cumulative effect cannot be determined, it is necessary to apply the new accounting principles prospectively at the earliest practical date. If it is not feasible to retrospectively apply the change in principle, the reason that this is not possible and the method used to report the change is required to be disclosed. The statement also provides that changes in accounting for depreciation, depletion or amortization should be treated as changes in accounting estimate inseparable from a change in accounting principle and that disclosure of the preferability of the change is required. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005.

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment." SFAS No. 123(R) revises SFAS No. 123, "Accounting for Stock-Based Compensation," and focuses on accounting for share-based payments for services provided by employee to employer. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model, and either a binomial or Black-Scholes model may be used. During the first quarter of 2005, the Securities and Exchange Commission (SEC) approved a new rule for public companies to delay the adoption of this standard. In April 2005, the SEC took further action to amend Regulation S-X to state that the provisions of SFAS No. 123(R) will be effective beginning with the first annual or interim reporting period of the registrant's first fiscal year beginning on or after June 15, 2005 for all non-small business issuers. As a result, the Company will not adopt this SFAS until the first quarter of 2006. The Company plans to use the modified prospective application method as detailed in SFAS No. 123(R). At this time, management does not believe that the adoption of SFAS No. 123(R) will materially impact the Company's operating results, nor will there be any impact on future cash flows. See "Stock-Based Compensation" below for further information.

In October 2005, the FASB issued FSP FAS 123(R)-2, "Practical Accommodation to the Application of Grant Date as defined in FASB Statement No. 123(R)." This FSP provides guidance on the definition and practical application of "grant date" as described in SFAS No. 123(R). The grant date is described as the date that the employee and employer have met a mutual understanding of the key terms and conditions of an award. The other elements of the definition of grant date are: 1) the award must be authorized, 2) the employer must be obligated to transfer assets or distribute equity instruments so long as the employee has provided the necessary service and 3) the employee is affected by changes in the company's stock price. To determine the grant date, the Company is allowed to use the date the award is approved in accordance with its corporate governance requirements so long as the three elements described above are met. Furthermore, the recipient cannot negotiate the award's terms and conditions with the employer and the key terms and conditions of the award are communicated to all recipients within a reasonably short time period from the approval date. The Company will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

In November 2005, the FASB issued FSP FAS 123(R)-3 "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," which provides a simpler, more practical transition election relating to the calculation of the "APIC pool." The APIC pool is defined as the pool of excess tax benefits available to absorb tax deficiencies occurring after the adoption of SFAS No. 123(R). Under this FSP, companies can elect to perform simpler computations to derive the beginning balance of the APIC pool as well as the impact on the APIC pool of fully vested and outstanding awards as of the SFAS No. 123(R) adoption date. The beginning balance can be computed by taking the sum of all tax benefits incurred prior to the adoption of SFAS No. 123(R) from stock-based compensation plans less the tax effected (using a blended statutory rate) pro forma stock-based compensation cost. In addition, increases to the APIC pool for fully vested awards can be calculated by multiplying the tax rate times the tax benefit of the deduction. The calculation of any awards that are partially vested or granted after the SFAS No. 123(R) adoption date will not be affected by this FSP and will be calculated in accordance with SFAS No. 123(R) which requires that only the excess tax benefit or deficiency of the tax deduction over the tax effect of the compensation cost recognized should be considered for the APIC pool. Also under the FSP, all tax benefits recognized on fully vested awards and the excess tax benefits for partially vested and new awards will be reported on the Statement of Cash Flows as a component of financing activities. Companies will have up to one year after adopting SFAS No. 123(R) to decide to elect and disclose whether they plan to use the alternative method or the original method prescribed in SFAS No. 123(R) for the calculation of the APIC pool. The Company will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

In February 2006, the FASB issued FSP FAS 123(R)-4, "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement upon the Occurrence of a Contingent Event." Within certain share-based payment plans, a company can be required to settle outstanding options upon the occurrence of certain events, such as a change in control or liquidity of a company or the death or disability of the shareholder. This FSP amends paragraphs 32 and A229 of SFAS No. 123(R) to incorporate a probability assessment by a company. Under SFAS No. 123(R), it is required that options and similar instruments be classified as liabilities if the entity can be required under any circumstances to settle the instrument in cash or other assets. Under the FSP, a cash settlement feature

that can be exercised only upon the occurrence of a contingent event that is outside of the employee's control does not meet the criteria for liability classification, and should remain to be classified in equity, unless it becomes probable that the contingent event will occur. The effective date for the guidance in this FSP is upon the initial adoption of SFAS No. 123(R). The Company will adopt this FSP in conjunction with the adoption of SFAS No. 123(R).

### ***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 is valued at average cost. Tubular goods and well equipment is 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, geophysics, 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. In 2003, the Company recorded impairments related to the loss of a reversionary interest in its Kurten field and a field in the East region. These impairments totaled \$93.8 million. During 2004, the Company recorded total impairments of \$3.5 million. 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.

### ***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. The Company realized \$11.4 million, \$9.2 million, and \$9.7 million of brokered natural gas margin in 2005, 2004, and 2003, 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, 2005 and 2004 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 \$5.6 million and \$5.3 million at December 31, 2005 and 2004, 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 inventories, production or other contractual commitments. All hedge transactions are subject to the Company's risk management policy which does not permit trading activities. Gains or losses on these hedging activities are generally recognized over the period that its inventories, 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 would be 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 10 of the Notes to the Consolidated Financial Statements for further discussion.

### **Stock Based Compensation**

The Company accounts for stock-based compensation in accordance with the intrinsic value based method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Under the intrinsic value based method, the Company records no compensation expense for stock options granted when the exercise price for options granted is equal to the fair value of the Company's common stock on the date of the grant.

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.

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 to stock-based employee compensation. The Earnings per Share amounts for prior periods have been retroactively adjusted to reflect the 3-for-2 split of the Company's common stock effective March 31, 2005.

Year Ended December 31,			
(In thousands, except per share amounts)	2005	2004	2003
<b>Net Income, as reported</b>	<b>\$ 148,445</b>	\$ 88,378	\$ 21,132
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	967	1,571	1,950
<b>Pro forma Net Income</b>	<b>\$ 147,478</b>	\$ 86,807	\$ 19,182
<b>Earnings per Share:</b>			
Basic - as reported	\$ 3.04	\$ 1.81	\$ 0.44
Basic - pro forma	\$ 3.02	\$ 1.78	\$ 0.40
Diluted - as reported	\$ 2.99	\$ 1.79	\$ 0.44
Diluted - pro forma	\$ 2.97	\$ 1.76	\$ 0.40
Weighted Average Common Shares Outstanding	48,856	48,733	48,074
Diluted Common Shares	49,725	49,339	48,435

The fair value of stock options included in the pro forma results for each of the three years is not necessarily indicative of future effects on net income and earnings per share. As of January 1, 2006, the Company will adopt SFAS No. 123(R), as discussed above in the "Recently Issued Accounting Pronouncements" section.

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 is expected to reduce the Company's compensation expense related to these options by approximately \$0.2 million for 2006.

The assumptions used in the fair value method calculation as well as additional stock based compensation information are disclosed in the following table.

(In thousands, except per share amounts)	Year Ended December 31,		
	2005	2004	2003
Compensation Expense in Net Income, as reported <sup>(1)</sup>	\$ 5,965	\$ 4,043	\$ 1,001
Weighted Average Value per Option Granted During the Period <sup>(2) (3)</sup>	\$ —	\$ 11.31	\$ 6.77
<b>Assumptions <sup>(3)</sup></b>			
Stock Price Volatility	—	38.4%	35.3%
Risk Free Rate of Return	—	3.3%	2.5%
Dividend Rate (Per year)	\$ 0.147	\$ 0.107	\$ 0.107
Expected Term (In years)	4	4	4

(1) Compensation expense is defined as expense related to the vesting of stock grants, net of tax. Compensation expense for the years ended December 31, 2005 and 2004 also includes \$2.1 million and \$2.0 million, respectively, net of tax related to performance shares.

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

(3) There were no stock options issued during the year ended December 31, 2005.

### 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, 2005, and 2004, 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, 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:

(In thousands)	December 31,	
	2005	2004
Unproved Oil and Gas Properties _____	\$ 107,787	\$ 94,795
Proved Oil and Gas Properties _____	1,970,407	1,646,841
Gathering and Pipeline Systems _____	178,876	160,951
Land, Building and Improvements _____	4,892	4,860
Other _____	33,077	31,261
	<b>2,295,039</b>	1,938,708
Accumulated Depreciation, Depletion and Amortization _____	(1,056,984)	(944,627)
	<b>\$ 1,238,055</b>	\$ 994,081

As of January 1, 2005, the Company adopted FSP FAS 19-1, "Accounting for Suspended Well Costs." Upon adoption of the FSP, the Company evaluated all existing capitalized exploratory well costs under the provisions of the FSP. For further details on the provisions of this FSP, see Note 1 of the Notes to the Consolidated Financial Statements. The following table reflects the net changes in capitalized exploratory well costs during 2005, 2004 and 2003.

(In thousands)	December 31,		
	2005	2004	2003
Beginning balance at January 1 _____	\$ 8,591	\$ 3,681	\$ 3,757
Additions to capitalized exploratory well costs pending the determination of proved reserves _____	6,132	8,591	3,681
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves _____	(1,069)	(3,395)	(2,881)
Capitalized exploratory well costs charged to expense _____	(7,522)	(286)	(876)
Ending balance at December 31	<b>\$ 6,132</b>	\$ 8,591	\$ 3,681

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

(In thousands)	December 31,		
	2005	2004	2003
Capitalized exploratory well costs that have been capitalized for a period of one year or less _____	\$ 6,132	\$ 8,591	\$ 3,681
Capitalized exploratory well costs that have been capitalized for a period greater than one year _____	—	—	—
Balance at December 31	<b>\$ 6,132</b>	\$ 8,591	\$ 3,681
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year _____	\$ —	\$ —	\$ —

At December 31, 2005 and 2003, the Company had no wells that had completed drilling and a determination of whether proved reserves existed could not be made.

At December 31, 2004, the Company had 3 wells that had completed drilling and 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 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. This impairment charge was recorded due to the capitalized cost of the field exceeding the future undiscounted cash flows. This charge is reflected in the operating results of the Company and was measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related field.

As part of the 2001 Cody acquisition, we acquired an interest in certain oil and gas properties in the Kurten field, as general partner of a partnership and as an operator. We had approximately a 25% interest in the field, including a one percent interest in the partnership. Under the partnership agreement, we had the right to a reversionary working interest that would bring our ultimate interest to 50% upon the limited partner reaching payout. Based on the addition of this reversionary interest, and because the field has over a 40-year reserve life, approximately \$91 million was allocated to this field under purchase accounting at the time of the acquisition. Additionally, the limited partner had the sole option to trigger a liquidation of the partnership.

Effective February 13, 2003, liquidation of the partnership commenced at the election of the limited partner. In connection with the liquidation, an appraisal was required to be obtained to allocate the interest in the partnership assets. Additionally, the Company was required to test the field for recoverability in accordance with SFAS No. 144. Pursuant to the terms of the partnership agreement and based on the appraised value of the partnership assets it was not possible for us to obtain the reversionary interest as part of the liquidation. Due to the impact of the loss of the reversionary interest on future estimated net cash flows of the Kurten field, the limited partner's decision and our decision to proceed with the liquidation, an impairment review was performed which required an impairment charge in 2003 of \$87.9 million (\$54.4 million after-tax). This impairment charge is reflected in the 2003 Statement of Operations as an operating expense but did not impact our cash flows.

During 2003 the Company divested of certain non-strategic assets. The primary assets sold included properties in Pennsylvania that were sold for \$16.1 million, and resulted in a gain of \$6.9 million. Additionally, the Company divested of a water treatment facility in the amount of \$3.4 million, which resulted in a gain of \$2.5 million.

### 3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31	
(In thousands)	2005	2004
Accounts Receivable		
Trade Accounts _____	\$ 147,016	\$ 105,378
Joint Interest Accounts _____	14,319	13,554
Current Income Tax Receivable _____	12,239	10,796
Other Accounts _____	315	1,312
	<b>173,889</b>	131,040
Allowance for Doubtful Accounts _____	(5,641)	(5,286)
	<b>\$ 168,248</b>	\$ 125,754
Inventories		
Natural Gas and Oil in Storage _____	\$ 18,279	\$ 17,631
Tubular Goods and Well Equipment _____	7,161	6,387
Pipeline Imbalances _____	(824)	31
	<b>\$ 24,616</b>	\$ 24,049
Other Current Assets		
Derivative Contracts _____	\$ 1,736	\$ 2,906
Drilling Advances _____	2,169	6,180
Prepaid Balances _____	6,939	4,173
Other Accounts _____	304	246
	<b>\$ 11,148</b>	\$ 13,505
Accounts Payable		
Trade Accounts _____	\$ 18,227	\$ 12,808
Natural Gas Purchases _____	12,208	8,669
Royalty and Other Owners _____	49,312	35,369
Capital Costs _____	37,489	26,203
Taxes Other Than Income _____	10,329	5,634
Drilling Advances _____	5,760	7,102
Wellhead Gas Imbalances _____	2,175	1,991
Other Accounts _____	4,506	7,193
	<b>\$ 140,006</b>	\$ 104,969
Accrued Liabilities		
Employee Benefits _____	\$ 9,020	\$ 10,123
Taxes Other Than Income _____	16,188	14,191
Interest Payable _____	6,818	6,569
Other Accounts _____	3,133	1,725
	<b>\$ 35,159</b>	\$ 32,608
Other Liabilities		
Postretirement Benefits Other Than Pension _____	\$ 6,517	\$ 4,717
Accrued Pension Cost _____	5,904	5,089
Rabbi Trust Deferred Compensation Plan _____	4,883	4,199
Accrued Plugging and Abandonment Liability _____	42,991	40,375
Other Accounts _____	6,899	6,649
	<b>\$ 67,194</b>	\$ 61,029

#### 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, and the Company made its first \$20 million payment during 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

To partially fund the cash portion of the acquisition of Cody Company in August 2001, the Company issued \$170 million of Notes to a group of seven institutional investors in a private placement transaction in July 2001. 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 \$90 million was outstanding at December 31, 2005. The facility can be expanded up to \$350 million, either with the existing banks or new banks. This 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 to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or 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 \$530 million, which can be expanded up to \$630 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 in the years ended December 31, 2005, 2004, and 2003 were 6.9%, 4.2% and 1.9%, respectively. As of December 31, 2005, the weighted average interest rate on the Company's credit facility was 7.25%. As of December 31, 2004, the Company had no borrowings outstanding on its credit facility. 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 with all covenants contained in its various debt agreements at December 31, 2005 and 2004 and during the years then ended.

## 5. Employee Benefit Plans

### Pension Plan

The Company has a 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 measurement date used to measure pension benefit amounts is December 31, 2005.

The Company has a 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. This plan is unfunded.

### Components of Net Periodic Benefit Cost

Net periodic pension cost of the Company during the last three years is comprised of the following:

(In thousands)	2005	2004	2003
<b>Qualified</b>			
Current Year Service Cost _____	\$ 2,485	\$ 1,619	\$ 1,481
Interest Cost _____	1,896	1,697	1,515
Expected Return on Plan Assets _____	(1,507)	(1,474)	(999)
Amortization of Prior Service Cost _____	99	88	88
Recognized Net Actuarial Loss _____	921	383	415
Net Periodic Pension Cost	\$ 3,894	\$ 2,313	\$ 2,500

(In thousands)	2005	2004	2003
<b>Non-Qualified</b>			
Current Year Service Cost _____	\$ (682)	\$ 395	\$ 280
Interest Cost _____	85	381	163
Amortization of Prior Service Cost _____	77	77	77
Recognized Net Actuarial (Gain) / Loss _____	(22)	428	187
Net Periodic Pension (Income) / Cost	\$ (542)	\$ 1,281	\$ 707

### *Obligations and Funded Status*

The following table illustrates the funded status of the Company's pension plans at December 31:

(In thousands)	2005		2004	
	Qualified	Non-Qualified	Qualified	Non-Qualified
<b>Actuarial Present Value of:</b>				
Accumulated Benefit Obligation _____	\$ 29,669	\$ 1,204	\$ 23,181	\$ 3,579
Projected Benefit Obligation _____	\$ 39,449	\$ 1,762	\$ 29,809	\$ 6,257
Fair Value of Plan Assets _____	23,765	—	18,092	—
Projected Benefit Obligation in Excess of Plan Assets _____	15,684	1,762	11,717	6,257
Unrecognized Net Actuarial Loss _____	(14,899)	(498)	(9,846)	(4,374)
Unrecognized Prior Service Cost _____	(269)	(245)	(248)	(322)
Adjustment to Recognize Minimum Liability _____	5,388	185	3,466	2,018
Accrued Pension Cost	\$ 5,904	\$ 1,204	\$ 5,089	\$ 3,579

The change in the combined projected benefit obligation of the Company's qualified and non-qualified pension plans during the last three years is explained as follows:

(In thousands)	2005	2004	2003
Beginning of Year _____	\$ 36,066	\$ 33,547	\$ 26,042
Service Cost _____	1,803	2,014	1,761
Interest Cost _____	1,981	2,078	1,678
Actuarial Loss _____	1,852	1,798	4,679
Plan Amendments _____	120	—	—
Benefits Paid _____	(611)	(3,371)	(613)
End of Year	\$ 41,211	\$ 36,066	\$ 33,547

The change in the qualified plan assets at fair value of the Company's pension plan during the last three years is explained as follows:

(In thousands)	2005	2004	2003
Beginning of Year _____	\$ 18,092	\$ 18,683	\$ 10,279
Actual Return on Plan Assets _____	1,544	957	2,446
Employer Contribution _____	5,000	2,000	6,735
Benefits Paid _____	(611)	(3,371)	(613)
Expenses Paid _____	(260)	(177)	(164)
End of Year	\$ 23,765	\$ 18,092	\$ 18,683

The reconciliation of the combined funded status of the Company's qualified and non-qualified pension plans at the end of the last three years is explained as follows:

(In thousands)	2005	2004	2003
Funded Status <sup>(1)</sup>	<b>\$ 17,446</b>	\$ 17,974	\$ 14,864
Unrecognized Net Actuarial Loss	<b>(15,397)</b>	(14,220)	(12,540)
Unrecognized Net Prior Service Cost	<b>(514)</b>	(570)	(735)
Net Amount Recognized	<b>\$ 1,535</b>	\$ 3,184	\$ 1,589
Accrued Benefit Liability - Qualified Plan	<b>\$ 5,904</b>	\$ 5,089	\$ 2,664
Accrued Benefit Liability - Non-Qualified Plan	<b>1,204</b>	3,579	3,171
Intangible Asset	<b>(454)</b>	(570)	(735)
Accumulated Other Comprehensive Income	<b>(5,119)</b>	(4,914)	(3,511)
Net Amount Recognized	<b>\$ 1,535</b>	\$ 3,184	\$ 1,589

(1) The qualified and non-qualified pension plans are in an under-funded position for 2005, 2004 and 2003 as the projected benefit obligation exceeds the plan assets.

### Additional Information

The amounts included in Other Comprehensive Income as a result of increases in the minimum liability of the Company's pension plans are as follows as of December 31:

(In thousands)	2005	2004	2003
Qualified Plan	<b>\$ 1,900</b>	\$ 2,199	\$ (870)
Non-Qualified Plan	<b>(1,695)</b>	(795)	2,203

### Assumptions

Assumptions used to determine projected pension benefit obligations are as follows:

(In thousands)	2005	2004	2003
Discount Rate	<b>5.50%</b>	5.75%	6.25%
Rate of Compensation Increase	<b>4.00%</b>	4.00%	4.00%

Assumptions used to determine net periodic pension costs are as follows:

(In thousands)	2005	2004	2003
Discount Rate	<b>5.75%</b>	6.25%	6.50%
Expected Long-Term Return on Plan Assets	<b>8.00%</b>	8.00%	8.00%
Rate of Compensation Increase	<b>4.00%</b>	4.00%	4.00%

The long-term expected rate of return on plan assets used in 2005, 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.

### Plan Assets

At December 31, 2005 and 2004, the non-qualified pension plan did not have plan assets. The plan assets of the Company's qualified pension plan at December 31, 2005 and 2004, by asset category are as follows:

(In thousands)	2005		2004	
	Amount	Percent	Amount	Percent
Equity securities _____	\$ 19,556	82%	\$ 13,934	77%
Debt securities _____	840	4%	3,226	18%
Other <sup>(1)</sup> _____	3,369	14%	932	5%
Total	\$ 23,765	100%	\$ 18,092	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 that are within a range of approximately 60% to 80% for equity securities and approximately 20% to 40% for fixed income securities.

### Cash Flows

#### Contributions

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2005 the Company did not have any required minimum funding obligations; however, it chose to fund \$5 million into the plan. In 2006 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 2006.

#### 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
2006 _____	\$ 828	\$ 42	\$ 870
2007 _____	848	54	902
2008 _____	916	74	990
2009 _____	1,106	85	1,191
2010 _____	1,256	176	1,432
Years 2011 - 2015 _____	10,878	1,418	12,296

#### 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. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 245 retirees and their dependants at the end of 2005 and 251 retirees and their dependants at the end of 2004. The measurement date used to measure postretirement benefits other than pensions is December 31, 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 amortization benefit of the unrecognized transition obligation amount below are the effects of plan amendments during 1996, 2000 and 2004. The remaining unamortized balance is \$3.9 million which will be amortized over the next six years.

#### *Components of Net Periodic Benefit Cost*

Postretirement benefit costs recognized during the last three years are as follows:

<i>(In thousands)</i>	<b>2005</b>	2004	2003
Current Year Service Cost _____	<b>\$ 675</b>	\$ 671	\$ 265
Interest Cost _____	<b>605</b>	784	385
Recognized Net Actuarial Gain _____	<b>(79)</b>	(59)	(155)
Amortization of Prior Service Cost _____	<b>910</b>	1,211	—
Amortization of Net Obligation at Transition _____	<b>648</b>	662	662
Total Postretirement Benefit Cost	<b>\$ 2,759</b>	\$ 3,269	\$ 1,157

#### *Obligations and Funded Status*

The funded status of the Company's postretirement benefit obligation at December 31, 2005, 2004 and 2003 is comprised of the following:

<i>(In thousands)</i>	<b>2005</b>	2004	2003
Beginning of Year <sup>(1)</sup> _____	<b>\$ 14,101</b>	\$ 6,181	\$ 6,185
Service Cost _____	<b>675</b>	671	265
Interest Cost _____	<b>605</b>	784	386
Amendments _____	<b>(1,434)</b>	6,901	—
Actuarial (Gain) / Loss _____	<b>(876)</b>	864	221
Benefits Paid _____	<b>(1,278)</b>	(1,300)	(876)
End of Year <sup>(1)</sup> _____	<b>\$ 11,793</b>	\$ 14,101	\$ 6,181

<sup>(1)</sup> The postretirement plan is in an under-funded position for 2005, 2004 and 2003 since the projected benefit obligation exceeds the plan assets. The postretirement plan does not have any plan assets.

The change in the accumulated postretirement benefit obligation during the last three years is presented as follows:

<i>(In thousands)</i>	<b>2005</b>	2004	2003
Fair Value of Plan Assets _____	<b>\$ —</b>	\$ —	\$ —
Funded Status _____	<b>11,793</b>	14,101	6,181
Unrecognized Net Gain _____	<b>2,475</b>	814	1,736
Unrecognized Net Prior Service Cost _____	<b>(3,366)</b>	(5,691)	—
Unrecognized Net Transition Obligation _____	<b>(3,888)</b>	(4,631)	(5,293)
Accrued Postretirement Benefit Liability	<b>\$ 7,014</b>	\$ 4,593	\$ 2,624

## Assumptions

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

	2005	2004	2003
Discount Rate <sup>(1)</sup> _____	5.50%	5.75%	6.25%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year _____	9.00%	10.00%	8.00%
Rate to Which the Cost Trend Rate is Assumed to Decline (the Ultimate Trend Rate) _____	5.00%	5.00%	N/A
Year that the Rate Reaches the Ultimate Trend Rate _____	2010	2009	2009

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2005, 2004 and 2003, respectively, the beginning of year discount rates of 5.75%, 6.25% and 6.50% were used.

The health care cost trend rate used to measure the expected cost from 2000 to 2003 for medical benefits to retirees was 8%. 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 will be under a fully-insured arrangement which replaces the former self-funded plan. Benefits under this new arrangement are expected to be comparable to benefits under the self-funded plan. The Company subsidy will be limited to 60% of the expected annual fully-insured premium. For all participants of any age, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, is 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 purchased individual life insurance policies on a fully insured basis for all retirees retiring before January 1, 2006. Effective January 1, 2006, postretirement life insurance benefits will not be provided to new retirees.

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 _____	\$ 12	\$ (13)
Effect on postretirement benefit obligation _____	131	(147)

## Cash Flows

### Contributions

The Company expects to contribute approximately \$0.6 million to the postretirement benefit plan in 2006.

### 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)	
2006 _____	\$ 571
2007 _____	579
2008 _____	580
2009 _____	594
2010 _____	616
Years 2011 - 2015 _____	3,894

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces 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 the Company has amended the postretirement benefit plan to exclude prescription drug benefits to participants age 65 and older effective January 1, 2006, management believes this FSP will not have an impact on operating results, financial position or cash flows of the Company.

#### *Savings Investment Plan*

The Company has a Savings Investment Plan (SIP), which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary, and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of \$1.6 million, \$1.4 million and \$1.4 million in 2005, 2004, and 2003, respectively. The Company matches employee contributions dollar-for-dollar on the first 6% 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 6% 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, 2005, the balance in the Deferred Compensation Plan's rabbi trust was \$4.9 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 year presented.

## 6. Income Taxes

Income tax expense (benefit) is summarized as follows:

(In thousands)	Year Ended December 31,		
	2005	2004	2003
<b>Current</b>			
Federal	\$ 42,976	\$ 14,767	\$ 22,826
State	5,185	3,710	2,075
Total	48,161	18,477	24,901
<b>Deferred</b>			
Federal	37,565	31,779	(8,549)
State	2,063	(10)	(1,289)
Total	39,628	31,769	(9,838)
Total Income Tax Expense	\$ 87,789	\$ 50,246	\$ 15,063

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

(In thousands)	Year Ended December 31,		
	2005	2004	2003
Statutory Federal Income Tax Rate	35%	35%	35%
Computed "Expected" Federal Income Tax	\$ 82,682	\$ 48,518	\$ 15,065
State Income Tax, Net of Federal Income Tax Benefit	7,030	4,353	1,334
Other, Net	(1,923) <sup>(1)</sup>	(2,625) <sup>(2)</sup>	(1,336) <sup>(3)</sup>
Total Income Tax Expense	\$ 87,789	\$ 50,246	\$ 15,063

(1) 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.

(2) 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.

(3) Other, Net includes credit adjustments of \$0.8 million related to the recognition of benefit for state statutory depletion in excess of basis and \$0.5 million related to the recognition of a benefit for a state net operating loss.

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

(In thousands)	Year Ended December 31,	
	2005	2004
<b>Deferred Tax Liabilities</b>		
Property, Plant and Equipment	\$ 288,602	\$ 246,962
Items Accrued for Financial Reporting Purposes	1,720	1,358
Total	290,322	248,320
<b>Deferred Tax Assets</b>		
Net Operating Loss Carryforwards	2,591	2,045
Items Accrued for Financial Reporting Purposes	22,840	21,290
Other Comprehensive Income	9,830	12,865
Total	35,261	36,200
Net Deferred Tax Liabilities	\$ 255,061	\$ 212,120

As of December 31, 2005, the Company had a net operating loss carryforward of \$50.3 million for state income tax reporting purposes, the majority of which will expire between 2013 and 2025 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 and Drilling Rig Commitments*

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems in Canada, the West and the East. The remaining terms on these agreements range from 2 to 22 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, 2005 are as follows:

*(In thousands)*

2006	\$ 11,661
2007	11,626
2008	8,213
2009	3,381
2010	3,381
Thereafter	55,504
	<u>\$ 93,766</u>

The Company also has three drilling rigs in the Gulf Coast under contract that are not yet delivered and two existing rigs in the Gulf Coast under contract through 2008. As of December 31, 2005, the Company is obligated over the next 4 years to pay \$104.3 million as follows:

*(In thousands)*

2006	\$ 26,055
2007	41,245
2008	27,340
2009	9,675
	<u>\$ 104,315</u>

Subsequent to December 31, 2005, the Company entered into an agreement for one additional drilling rig in the Gulf Coast. The total commitment over the next four years is \$27.4 million, of which \$0.8 million, \$9.1 million, \$9.1 million and \$8.4 million will be paid out during the years 2006, 2007, 2008 and 2009, respectively.

### *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 four more years. Most of the Company's leases expire within five years and may be renewed. Rent expense under such arrangements totaled \$9.1 million, \$8.7 million, and \$8.5 million for the years ended December 31, 2005, 2004, and 2003, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2005 are as follows:

*(In thousands)*

2006	\$ 4,876
2007	4,633
2008	4,541
2009	3,207
2010	489
Thereafter	—
	<u>\$ 17,746</u>

### *Contingencies*

The Company is 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 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.

**Wyoming Royalty Litigation.** In January 2002, 13 overriding royalty owners sued the Company in Wyoming federal district court, as reported in previous filings. The plaintiffs made claims pertaining to deductions from their overriding royalty and claims concerning penalties for improper reporting. As a result of several decisions by the Court favorable to the Company, the case was settled in September 2005 with no payment from the Company and a dismissal with prejudice of all claims by plaintiffs. The settlement included provisions for reporting and payment going forward. Management has reversed the reserve it had recorded regarding this case, which had an immaterial impact on the Company's consolidated financial statements.

**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 it had taken improper deductions from the royalty and 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 has postponed the trial date from April 17, 2006, in light of a case pending before the West Virginia Supreme Court of Appeals which may decide issues of law that may apply to the issue of deductibility of post-production expenses. 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 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 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, 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 are allowed to amend pleadings or add additional parties to the litigation. Due to the abatement of the case, the Company has not had the opportunity to conduct discovery in this matter. The Company estimates that production revenue from this field since Cody Energy, LLC acquired title is approximately \$15.7 million, and that the carrying value of this property is approximately \$33.6 million.

Although the investigation into this claim continues, the Company intends to vigorously defend the case. Should the Company receive an adverse ruling in this case, an impairment review would be assessed to determine whether the carrying value of the property is recoverable. Management cannot currently determine the likelihood of an unfavorable outcome or range of any potential loss should the outcome be unfavorable. Accordingly, there has been no reserve established for this matter.

**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 have

filed a counter claim against the Company, and one of the defendants has 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 3% 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. The defendant has filed a Motion for Reconsideration and Opposition to Proposed Order. The Court has not yet made a decision on these two motions.

**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 \$10.2 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:

(In thousands)	Year Ended December 31,		
	2005	2004	2003
Interest _____	\$ 17,366	\$ 16,415	\$ 18,298
Income Taxes _____	47,142	29,861	19,267

The Company recorded benefits of \$3.7 million, \$2.6 million and \$1.0 million for the years ended December 31, 2005, 2004 and 2003, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting.

## 9. Capital Stock

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.

### Incentive Plans

On April 29, 2004, the 2004 Incentive Plan was approved by the shareholders. Under the 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.

During 2005, the Board of Directors granted a series of 110,200 performance share awards to the executives of the Company. These awards are 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 period ending on April 30, 2008. 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. The performance shares qualify for variable accounting, and accordingly, are recorded at their fair value with compensation expense recognized over the performance period.

During 2005, the Company granted 19,600 restricted stock units to the non-employee Directors of the Company. These units immediately vest and will be paid out whenever the Director ceases to be a Director of the Company. For all restricted stock units, the Company recognized compensation expense equal to the market value of the Company's common stock on the grant date of the respective awards.

Information regarding stock options under the Company's 2004 Incentive Plan and the Prior Plans is summarized below:

		December 31,	
	2005	2004	2003
Shares Under Option at Beginning of Period	1,217,534	2,024,252	1,931,744
Granted	—	36,750	700,500
Exercised	300,493	793,775	518,079
Surrendered or Expired	3,693	49,693	89,913
Shares Under Option at End of Period	913,348	1,217,534	2,024,252
Options Exercisable at End of Period	895,848	565,994	767,579

For each of the three most recent years, the price range for outstanding options was \$11.63 to \$23.32 per share. The following tables provide more information about the options by exercise price and year.

Options with exercise prices between \$11.63 and \$15.00 per share:

		December 31,	
	2005	2004	2003
<b>Options Outstanding</b>			
Number of Options	225,575	344,945	667,002
Weighted Average Exercise Price	\$ 12.84	\$ 12.85	\$ 12.81
Weighted Average Contractual Term (In years)	1.1	2.0	2.6
<b>Options Exercisable</b>			
Number of Options	225,575	183,737	306,344
Weighted Average Exercise Price	\$ 12.84	\$ 12.86	\$ 12.69

Options with exercise prices between \$15.01 and \$23.32 per share:

		December 31,	
	2005	2004	2003
<b>Options Outstanding</b>			
Number of Options	687,773	872,589	1,357,250
Weighted Average Exercise Price	\$ 16.14	\$ 16.16	\$ 16.46
Weighted Average Contractual Term (In years)	1.9	2.7	3.4
<b>Options Exercisable</b>			
Number of Options	670,273	382,257	461,235
Weighted Average Exercise Price	\$ 16.13	\$ 16.29	\$ 17.61

### **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.

### **Treasury Stock**

In August 1998, the Board of Directors authorized the Company to repurchase up to two million shares of outstanding common stock at market prices. As a result of the 3-for-2 split of the Company's common stock in March 2005, this figure has been adjusted to three 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. During the year ended December 31, 2005, the Company repurchased 452,300 shares for a total cost of approximately \$19.2 million. The repurchased shares are held as treasury stock. Since the authorization date, the Company has repurchased 1,513,850 shares, or 50% of the total shares authorized for repurchase, for a total cost of approximately \$39.2 million. In 2005, the stock repurchase plan was funded from cash flow from operations. No treasury shares have been delivered or sold by the Company subsequent to the repurchase.

### **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, 2005 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.

The 3-for-2 split of the Company's common stock was consummated 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. As a result of the 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. 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.

## **10. 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, 2005		December 31, 2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<i>(In thousands)</i>				
<b>Debt</b>				
7.19% Notes	\$ 60,000	\$ 62,938	\$ 80,000	\$ 87,770
7.26% Notes	75,000	81,713	75,000	85,849
7.36% Notes	75,000	83,990	75,000	87,111
7.46% Notes	20,000	23,083	20,000	23,804
Credit Facility	90,000	90,000	—	—
	<b>\$ 320,000</b>	<b>\$ 341,724</b>	<b>\$ 250,000</b>	<b>\$ 284,534</b>

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, 2005, the Company had nine cash flow hedges open: eight natural gas price collar arrangements and one crude oil collar arrangement. At December 31, 2005, a \$20.7 million (\$12.9 million net of tax) unrealized loss was recorded to Accumulated Other Comprehensive Income, along with a \$22.4 million short-term derivative liability and a \$1.7 million short-term derivative receivable, which is shown in Other Current Assets on the Balance Sheet. 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, 2005 the Company would expect to reclassify to the Statement of Operations, over the next 12 months, \$12.9 million in after-tax charges associated with commodity hedges. This reclassification represents the net liability associated with open positions currently not reflected in earnings at December 31, 2005 related to anticipated 2006 production.

**Hedges on Production - Swaps.** From time to time, the Company enters into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of its production. These derivatives are not held for trading purposes. Under these price swaps, the Company receives a fixed price on a notional quantity of natural gas and crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. During 2005, natural gas price swaps covered 20,557 Mmcf, or 28% of the Company's gas production, fixing the sales price of this gas at an average of \$5.14 per Mcf.

At December 31, 2005, the Company had no open natural gas price swap contracts covering 2006 production.

From time to time, the Company enters into natural gas and crude oil derivative arrangements that do not qualify for hedge accounting under SFAS No. 133. These financial instruments are recorded at fair value at the balance sheet date. At December 31, 2005, the Company did not have any of these types of arrangements.

**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 2005, natural gas price collars covered 15,157 Mmcf of the Company's gas production, or 21% of gas production with a weighted average floor of \$5.59 per Mcf and a weighted average ceiling of \$8.61 per Mcf. During 2005, an oil price collar covered 365 Mbbl of the Company's crude oil production, or 21% of crude oil production with a weighted average floor of \$40.00 per Mbbl and a weighted average ceiling of \$50.50 per Mbbl.

At December 31, 2005, the Company had open natural gas price collar contracts covering its 2006 production as follows:

Contract Period	Natural Gas Price Collars		
	Volume in Mmcf	Weighted Average Ceiling / Floor	Net Unrealized Loss (In thousands)
<b>As of December 31, 2005</b>			
First Quarter 2006	6,702	\$12.74/\$8.25	
Second Quarter 2006	6,776	12.74/8.25	
Third Quarter 2006	6,850	12.74/ 8.25	
Fourth Quarter 2006	6,851	12.74/8.25	
<b>Full Year 2006</b>	<b>27,179</b>	<b>\$12.74/\$8.25</b>	<b>\$ (20,425)</b>

At December 31, 2005, the Company had one open crude oil price collar contract covering its 2006 production as follows:

Contract Period	Crude Oil Price Collar		
	Volume in Mbbl	Weighted Average Ceiling / Floor	Net Unrealized Loss (In thousands)
<b>As of December 31, 2005</b>			
First Quarter 2006 _____	90	\$76.00/\$50.00	
Second Quarter 2006 _____	91	76.00/50.00	
Third Quarter 2006 _____	92	76.00/50.00	
Fourth Quarter 2006 _____	92	76.00/50.00	
<b>Full Year 2006</b>	<b>365</b>	<b>\$76.00/\$50.00</b>	<b>\$ (317)</b>

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 each of 2005, 2004 and 2003, approximately 11% of the Company's total sales were made to one customer.

### **11. Adoption of SFAS 143, "Accounting for Asset Retirement Obligations"**

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized 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 adoption of SFAS No. 143 resulted in an increase of total liabilities because additional retirement obligations are required to be recognized, an increase in the recognized cost of assets because the retirement costs are added to the carrying amount of the long-lived asset and an increase in operating expense because of the accretion of the retirement obligation and additional depreciation and depletion. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities will also be recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2005 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company recorded a net-of-tax charge for the cumulative effect of change in accounting principle, in January of 2003, of approximately \$6.8 million (\$11.0 million before tax) and recorded a retirement obligation of approximately \$35.2 million. There was no impact on the Company's cash flows as a result of adopting SFAS No. 143.

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, 2005, 2004 and 2003 was \$1.4 million, \$1.7 million and \$2.1 million, respectively.

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, 2004 _____	\$ 40,375
Liabilities added during the current period _____	1,364
Liabilities settled during the current period _____	(110)
Current period accretion expense _____	1,419
Revisions to estimated cash flows _____	(57)
<b>Carrying amount of asset retirement obligation at December 31, 2005</b>	<b>\$ 42,991</b>

## 12. 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 outstanding stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

The following is a calculation of basic and diluted weighted average shares outstanding for the year ended December 31, 2005, 2004 and 2003:

(In thousands)	Year Ended December 31,		
	2005	2004	2003
Shares - basic	48,856,491	48,732,504	48,074,496
Dilution effect of stock options and awards at end of period	868,904	606,297	360,932
Shares - diluted	49,725,395	49,338,801	48,435,428
Stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect	—	—	1,448,666

## 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, 2005, 2004, and 2003 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 3, 2006, 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, 2005, 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:

<b>Natural Gas</b>			
Year Ended December 31,			
(Millions of cubic feet)	2005	2004	2003
<b>Proved Reserves</b>			
Beginning of Year _____	<b>1,134,081</b>	1,069,484	1,060,959
Revisions of Prior Estimates _____	<b>(1,543)</b>	(7,850)	(6,122)
Extensions, Discoveries and Other Additions _____	<b>185,884</b>	140,986	105,497
Production _____	<b>(73,879)</b>	(72,833)	(71,906)
Purchases of Reserves in Place _____	<b>17,567</b>	5,384	1,590
Sales of Reserves in Place _____	<b>(14)</b>	(1,090)	(20,534)
End of Year _____	<b>1,262,096</b>	1,134,081	1,069,484
<b>Proved Developed Reserves</b>	<b>944,897</b>	857,834	812,280
<b>Percentage of Reserves Developed</b>	<b>74.9%</b>	75.6%	76.0%

<b>Liquids</b>			
Year Ended December 31,			
(Thousands of barrels)	2005	2004	2003
<b>Proved Reserves</b>			
Beginning of Year _____	<b>11,384</b>	12,103	18,393
Revisions of Prior Estimates _____	<b>1,073</b>	185	307
Extensions, Discoveries and Other Additions _____	<b>334</b>	1,074	1,723
Production _____	<b>(1,747)</b>	(2,002)	(2,846)
Purchases of Reserves in Place _____	<b>419</b>	24	—
Sales of Reserves in Place _____	<b>—</b>	—	(5,474)
End of Year _____	<b>11,463</b>	11,384	12,103
<b>Proved Developed Reserves</b>	<b>9,127</b>	8,652	9,405
<b>Percentage of Reserves Developed</b>	<b>79.6%</b>	76.0%	77.7%

#### **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.

Year Ended December 31,			
(In thousands)	2005	2004	2003
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities _____	<b>\$ 2,290,147</b>	\$ 1,933,848	\$ 1,732,236
Aggregate Accumulated Depreciation, Depletion and Amortization _____	<b>1,052,654</b>	940,447	837,060

### 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,		
	2005	2004	2003
Property Acquisition Costs, Proved _____	<b>\$ 73,127</b>	\$ 3,953	\$ 1,524
Property Acquisition Costs, Unproved _____	<b>22,126</b>	18,250	14,056
Exploration and Extension Well Costs <sup>(1)</sup> _____	<b>102,957</b>	85,415	83,147
Development Costs _____	<b>208,124</b>	136,311	77,006
Total Costs	<b>\$ 406,334</b>	\$ 243,929	\$ 175,733

(1) Includes administrative exploration costs of \$12,423, \$11,354 and \$10,582 for the years ended December 31, 2005, 2004, and 2003, 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:

(In thousands)	Year Ended December 31,		
	2005	2004	2003
Operating Revenues _____	<b>\$ 581,849</b>	\$ 439,988	\$ 404,503
Costs and Expenses			
Production _____	<b>103,477</b>	84,015	77,315
Other Operating _____	<b>30,120</b>	27,787	20,090
Exploration <sup>(1)</sup> _____	<b>61,840</b>	48,130	58,119
Depreciation, Depletion and Amortization _____	<b>119,122</b>	114,906	195,659
Total Costs and Expenses _____	<b>314,559</b>	274,838	351,183
Income Before Income Taxes _____	<b>267,290</b>	165,150	53,320
Provision for Income Taxes _____	<b>100,353</b>	60,361	18,662
Results of Operations	<b>\$ 166,937</b>	\$ 104,789	\$ 34,658

(1) Includes administrative exploration costs of \$12,423, \$11,354 and \$10,582 for the years ended December 31, 2005, 2004, and 2003, 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, 2005, 2004, and 2003 for natural gas (\$ per Mcf) were \$9.53, \$6.26 and \$5.96, respectively, and for oil (\$ per Bbl) were \$58.48, \$41.24 and \$30.94, respectively. Future cash inflows were reduced by estimated future development and production costs based on year end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved. 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 probable as well as 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,		
	2005	2004	2003
Future Cash Inflows _____	<b>\$ 12,700,390</b>	\$ 7,561,728	\$ 6,742,214
Future Production Costs _____	<b>(2,271,917)</b>	(1,577,787)	(1,390,398)
Future Development Costs _____	<b>(536,333)</b>	(396,431)	(310,923)
Future Income Tax Expenses _____	<b>(3,588,877)</b>	(2,009,644)	(1,800,519)
Future Net Cash Flows _____	<b>6,303,263</b>	3,577,866	3,240,374
10% Annual Discount for Estimated Timing of Cash Flows _____	<b>(3,652,030)</b>	(1,997,509)	(1,760,966)
Standardized Measure of Discounted Future Net Cash Flows <sup>(1)</sup>	<b>\$ 2,651,233</b>	\$ 1,580,357	\$ 1,479,408

(1) The standardized measures of discounted future net cash flows before taxes were \$4,001,769, \$22,358,430 and \$2,196,038 for the years ended December 31, 2005, 2004, and 2003, 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,		
	2005	2004	2003
Beginning of Year _____	<b>\$ 1,580,357</b>	\$ 1,479,408	\$ 1,255,353
Discoveries and Extensions, Net of Related Future Costs _____	<b>494,773</b>	321,026	235,079
Net Changes in Prices and Production Costs _____	<b>1,278,303</b>	(17,976)	475,026
Accretion of Discount _____	<b>235,843</b>	219,604	171,590
Revisions of Previous Quantity Estimates, Timing and Other _____	<b>(49,550)</b>	(46,115)	(35,691)
Development Costs Incurred _____	<b>61,802</b>	32,940	27,529
Sales and Transfers, Net of Production Costs _____	<b>(471,638)</b>	(357,939)	(330,800)
Net Purchases (Sales) of Reserves in Place _____	<b>91,180</b>	10,853	(62,596)
Net Change in Income Taxes _____	<b>(569,837)</b>	(61,444)	(256,082)
End of Year _____	<b>\$ 2,651,233</b>	\$ 1,580,357	\$ 1,479,408

## SELECTED DATA (UNAUDITED)

### QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
<b>2005</b>					
Operating Revenues	\$ 144,074	\$ 151,884	\$ 161,757	\$ 225,082	\$ 682,797
Impairment of Oil and Gas Properties <sup>(1)</sup>	—	—	—	—	—
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 <sup>(2)</sup>	0.43	0.72	0.69	1.20	3.04
Diluted Earnings per Share <sup>(2)</sup>	0.42	0.71	0.68	1.18	2.99
<b>2004</b>					
Operating Revenues	\$ 136,604	\$ 119,742	\$ 119,423	\$ 154,639	\$ 530,408
Impairment of Oil and Gas Properties <sup>(1)</sup>	—	—	3,458	—	3,458
Operating Income	36,090	36,439	34,278	53,846	160,653
Net Income	19,011	19,318	17,822	32,227	88,378
Basic Earnings per Share <sup>(2)</sup>	0.39	0.40	0.37	0.66	1.81
Diluted Earnings per Share <sup>(2)</sup>	0.39	0.39	0.36	0.65	1.79

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

(2) All Earnings per Share figures have been retroactively adjusted for the 3-for-2 split of the Company's Common Stock effective March 31, 2005.

## 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, 2005, 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, 2005. 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, 2005, 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, 2005 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 AND EXECUTIVE OFFICERS OF THE REGISTRANT**

The information under the captions "Election of Directors", "Audit Committee" and "Code of Business Conduct" in the Company's definitive Proxy Statement in connection with the 2006 annual stockholders' meeting are incorporated by reference. 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 under the caption "Executive Compensation" in the Company's definitive Proxy Statement in connection with the 2006 annual stockholders' meeting is incorporated by reference.

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

The information under the captions "Beneficial Ownership of Over Five Percent of Common Stock", "Beneficial Ownership of Directors and Executive Officers", and "Equity Compensation Plan Information" in the Company's definitive Proxy Statement in connection with the 2006 annual stockholders' meeting are incorporated by reference.

### **ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS**

None.

### **ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES**

The information under the caption "Fees Billed by Independent Public Accountants for Services in 2005 and 2004" in the Company's definitive Proxy Statement in connection with the 2006 annual stockholders' meeting is incorporated by reference.

## **PART IV**

### **ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

#### **A. INDEX**

##### **1. Consolidated Financial Statements**

See Index on page 60.

##### **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 2, 2002).
3.4	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 2, 2002).
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	Form of Annual Target Cash Incentive Plan of the Company (Registration Statement No. 33-32553).
*10.3	Form of Incentive Stock Option Plan of the Company (Registration Statement No. 33-32553). (a) First Amendment to the Incentive Stock Option Plan (Post-Effective Amendment No. 1 to S-8 dated April 26, 1993).
*10.4	Savings Investment Plan & Trust Agreement of the Company (Form 10-K for 1991). (a) First Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993). (b) Second Amendment to the Savings Investment Plan dated May 21, 1993 (Form S-8 dated November 1, 1993). (c) First through Fifth Amendments to the Trust Agreement (Form 10-K for 1995). (d) Third through Fifth Amendments to the Savings Investment Plan (Form 10-K for 1996).
*10.5	Supplemental Executive Retirement Agreements of the Company (Form 10-K for 1991).

Exhibit Number	Description
*10.6	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).
*10.7	Second Amended and Restated 1994 Long-Term Incentive Plan of the Company (Form 10-K for 2001).
*10.8	Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (Form 10-K for 2001).
*10.9	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 1997).
*10.10	Deferred Compensation Plan of the Company as Amended September 1, 2001 (Form 10-K for 2001).
10.11	Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company (Form 10-K for 2001).
10.12	Lease Agreement between the Company and DNA COG, Ltd. dated April 24, 1998 (Form 10-K for 1998).
10.13	Credit Agreement dated as of December 17, 1998, between the Company and the banks named therein (Form 10-K for 1998).
*10.14	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
*10.15	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
*10.16	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
*10.17	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.18	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.19	2005 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 8-K for May 24, 2005).
*10.20	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).
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 6<sup>th</sup> of March 2006.

### 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
<u>/s/ Dan O. Dinges</u> Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 6, 2006
<u>/s/ Scott C. Schroeder</u> Scott C. Schroeder	Vice President and Chief Financial Officer (Principal Financial Officer)	March 6, 2006
<u>/s/ Henry C. Smyth</u> Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	March 6, 2006
<u>/s/ Robert F. Bailey</u> Robert F. Bailey	Director	March 6, 2006
<u>/s/ John G. L. Cabot</u> John G. L. Cabot	Director	March 6, 2006
<u>/s/ David M. Carmichael</u> David M. Carmichael	Director	March 6, 2006
<u>/s/ James G. Floyd</u> James G. Floyd	Director	March 6, 2006
<u>/s/ Robert L. Keiser</u> Robert L. Keiser	Director	March 6, 2006
<u>/s/ Robert Kelley</u> Robert Kelley	Director	March 6, 2006
<u>/s/ C. Wayne Nance</u> C. Wayne Nance	Director	March 6, 2006
<u>/s/ P. Dexter Peacock</u> P. Dexter Peacock	Director	March 6, 2006
<u>/s/ William P. Vititoe</u> William P. Vititoe	Director	March 6, 2006

# Corporate Information

## Officers

### **Dan O. Dinges**

*Chairman, President and  
Chief Executive Officer*

### **Michael B. Walen**

*Senior Vice President,  
Chief Operating Officer*

### **Scott C. Schroeder**

*Vice President and  
Chief Financial Officer*

### **J. Scott Arnold**

*Vice President, Land and  
Associate General Counsel*

### **Robert G. Drake**

*Vice President,  
Information Services and  
Operational Accounting*

### **Abraham D. Garza**

*Vice President,  
Human Resources*

### **Jeffrey W. Hutton**

*Vice President, Marketing*

### **Thomas S. Liberatore**

*Vice President,  
Regional Manager,  
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 Thursday, May 4, 2006, at 8:00 a.m. (CDT) at the corporate office in Houston, Texas.

## Corporate Office

Cabot Oil & Gas Corporation  
1200 Enclave Parkway  
Houston, Texas 77077  
P. O. Box 4544  
Houston, Texas 77210-4544  
(281) 589-4600  
[www.cabotog.com](http://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  
1100 Louisiana, 27th Floor  
Houston, Texas 77002

## 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](mailto: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  
(800) 524-4458  
(610) 382-7833 (Outside the U.S.)  
(888) 269-5221 (Hearing Impaired - TDD Phone)  
[shareowner@bankofny.com](mailto:shareowner@bankofny.com)  
[www.stockbny.com](http://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 23, 2005, 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 2005 quarterly reports on Form 10-Q and the 2005 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.



Cabot Oil & Gas Corporation

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