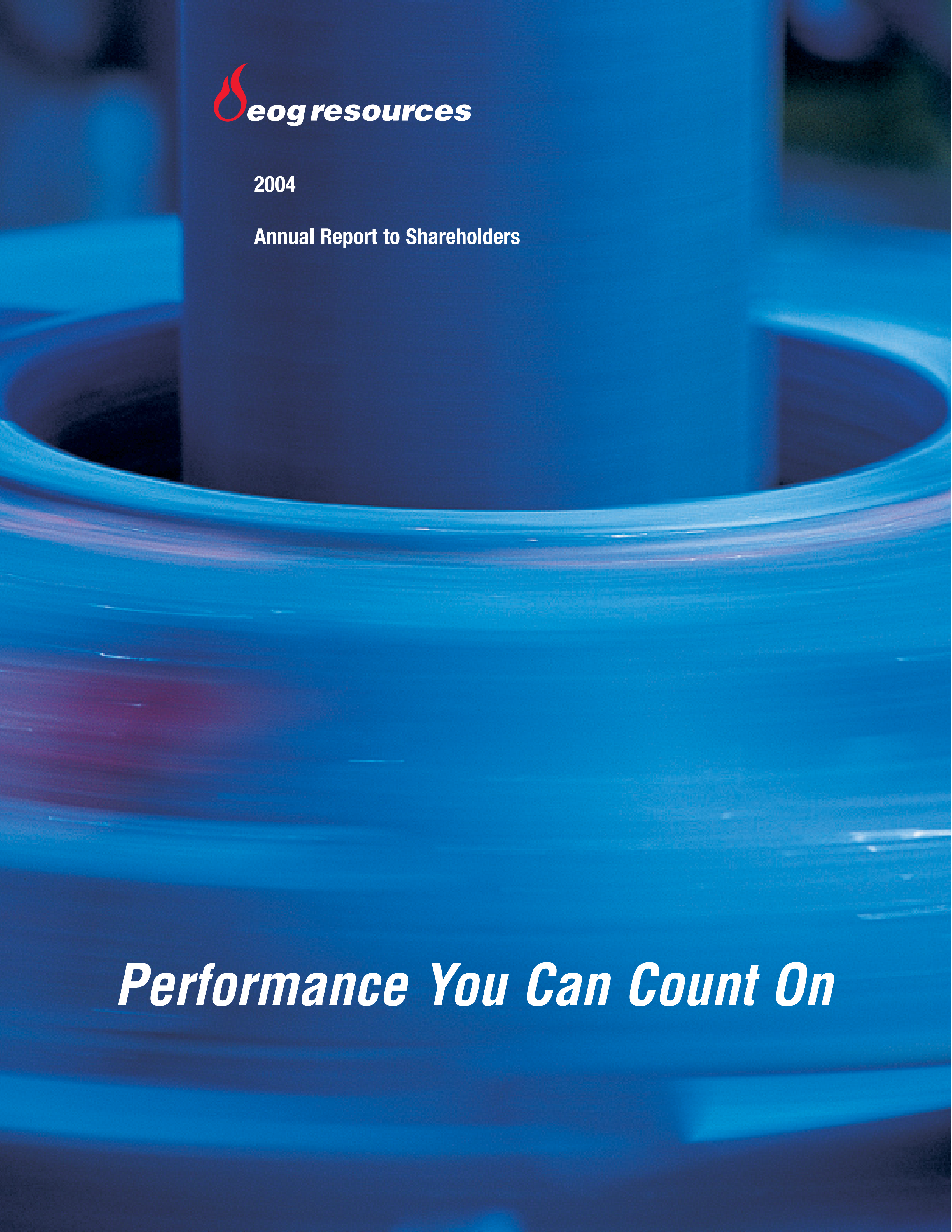


eog resources

2004

Annual Report to Shareholders

Performance You Can Count On

FINANCIAL AND OPERATING HIGHLIGHTS

(In millions, unless otherwise indicated)	2004	2003	2002
Net Operating Revenues	$ 2,271	$ 1,745	$ 1,095
Income Before Interest Expense and Income Taxes	$ 989	$ 713	$ 179
Net Income Available to Common	$ 614	$ 419	$ 76
Total Exploration and Development Expenditures	$ 1,510	$ 1,333	$ 836
Wellhead Statistics			
Natural Gas Volumes (MMcfd)	1,036	955	924
Natural Gas Price ($/Mcf)	$ 4.86	$ 4.40	$ 2.60
Crude Oil and Condensate Volumes (MBbld)	27.4	23.2	23.3
Crude Oil and Condensate Price ($/Bbl)	$ 40.22	$ 29.92	$ 24.56
Natural Gas Liquids Volumes (MBbld)	5.6	3.8	3.7
Natural Gas Liquids Price ($/Bbl)	$ 27.13	$ 21.13	$ 14.05

The Company

EOG Resources, Inc. is one of the largest independent (non-integrated) oil and natural gas companies in the United States with substantial proved reserves in the United States, Canada, offshore Trinidad and, to a lesser extent, the United Kingdom North Sea. EOG Resources, Inc. is listed on the New York Stock Exchange and is traded under the ticker symbol “EOG.”

On The Cover

A spinning drillbit reflects EOG’s high level of drilling activity and its continued focus on organic growth, a long-term strategy that positioned the company to achieve outstanding performance in 2004.

Highlights

- For 2004, EOG reported net income available to common of $614 million, compared to $419 million for 2003.
- At December 31, 2004, total company reserves were approximately 5.6 Tcfe, an increase of 430 Bcfe, or 8 percent higher than 2003. From drilling alone, EOG added 850 Bcfe of reserves in 2004.
- During 2004, total company production increased 10.4 percent on a daily basis, compared to 2003. EOG is targeting 13.5 percent organic production growth in 2005, which includes an 11 percent increase in natural gas production from the United States and Canada.
- At year-end 2004, EOG had approximately 400,000 acres under lease in the Texas Barnett Shale play with net production reaching 30 MMcfed during December.
- In the United Kingdom North Sea, EOG commenced production from two Southern Gas Basin wells in the third quarter of 2004 and the first quarter of 2005. These are EOG’s first producing assets in that region.
- In Trinidad, total 2004 production increased 25 percent, compared to 2003. EOG began natural gas sales to NGC for the N2000 ammonia plant in mid-2004. In February 2005, EOG announced a 10-year extension and amendments to the pricing terms of the SECC natural gas sales contract with NGC and signed a contract to supply natural gas to NGC for an LNG plant with start-up planned for mid-2006.
- A two-for-one stock split in the form of a stock dividend, announced in February 2005, was effective March 1, 2005. In addition, the cash dividend on the common stock was increased by 33 percent, following a 20 percent increase in 2004. Beginning with the dividend payable on April 29, 2005, the post-split quarterly cash dividend on the common stock will be $.04 per share, the fifth increase in six years.

Information regarding forward-looking statements is on page 21 of this annual report to shareholders.

For a glossary of terms see page 56.

Persistence Pays Superior Shareholder Returns

Mark G. Papa
Chairman and Chief Executive Officer

Edmund P. Segner, III
President and Chief of Staff

2004 was another banner year for EOG Resources with double-digit production growth and shareholder returns that well outpaced most peer companies. Especially noteworthy is our stock price performance viewed over the last five years. Clearly, our long-term strategy is working.

When we became an independent company in 1999, we announced our intention to concentrate on the fundamentals of the exploration and production business. Our priorities included:

- Focusing on per share results and working diligently to maintain our reputation as a rate of return driven company that creates superior shareholder value,
- Being financially conservative and managing our company with high ethical standards,
- Growing the company through the drillbit with an aggressive drilling program concentrating largely on the development of natural gas, along with select oil targets,
- Seeking higher return, tactical acquisition opportunities in areas where EOG is established, rather than pursuing big-ticket mergers and acquisitions,
- Ranking repeatedly as a low-cost industry operator,
- Continuing to explore and exploit our existing properties located in almost every major producing basin in the United States and Canada with a consistent approach,
- Adding new, big-target domestic plays to our existing program,
- Developing our offshore Trinidad properties, while at the same time seeking another new international venue that fits our strict selection criteria,
- Placing our dynamic employees in close proximity to the plays they explore and operate, and
- Attracting and retaining top technical talent, while developing and honing their skills, as we work toward being the exploration and production industry's 'employer of choice.'

Since we articulated this straightforward, flexible yet deliberate strategy, we have followed through with persistence and the result is strong performance over a chain of successful years.

Enhancing Shareholder Value

In keeping with EOG's ongoing dedication to enhancing shareholder returns, the board of directors recently approved a two-for-one stock split in the form of a stock dividend effective March 1, 2005. Following a 20 percent increase in early 2004, the board voted to again increase the common stock cash dividend 33 percent in 2005 to an indicated annual rate of $0.16 per post-split share. This represents the fifth increase in six years.

EOG reported record net income available to common of $614 million for 2004, compared to $419 million for 2003. For 2004, EOG's return on equity (ROE)(1) was 25 percent and return on capital employed (ROCE)(1) was 18 percent. Our return to shareholders(1) was 55 percent for the 12-month period.

In addition to our growth in net income and strong returns, EOG's 2004 cash flow essentially funded our capital program. We ended the year with a 27 percent debt-to-total capitalization ratio(1), down from 33 percent at year-end 2003. EOG also redeemed $50 million in preferred stock, further strengthening the balance sheet.

From an operations perspective, 2004 was a breakout year. Total company production increased 10.4 percent, as compared to 2003. We are targeting outstanding total company production growth of 13.5 percent in 2005 and 8 percent in 2006.

At year-end 2004, total company net proved reserves were approximately 5.6 Tcfe, an increase of 430 Bcfe, or 8 percent higher than 2003. For the 17th consecutive year, internal reserve estimates were within 5 percent of external reserve estimates prepared by the independent reserve engineering firm, DeGolyer and MacNaughton, that evaluated 77 percent of EOG's proved reserves on a Bcfe basis in 2004.

The impressive performance EOG achieved in 2004 was derived from our strong, established exploration and production activities. With a preference for organic growth, EOG's operations continue to expand and flourish. Once again, in 2004, EOG ranked as one of the five most active drillers in the United States.

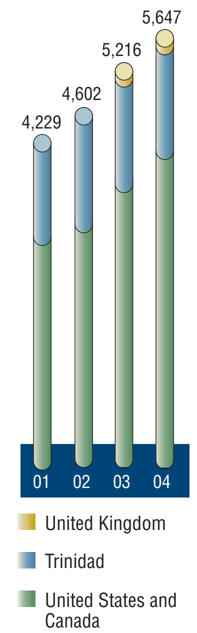
During 2004, we announced that we had identified a big target play located in the Fort Worth Basin of Texas. Potentially significant in scope, the Barnett Shale play is expected to generate a very high reinvestment rate of return, year after year. We have prospects for a multi-year drilling inventory for this notable discovery, which will be additive to our United States operations.

Establishing a firm foothold in the United Kingdom North Sea last year, EOG commenced production in the third quarter with current net production of approximately 35 MMcfed. In 2005, we have plans to expand our drilling efforts there.

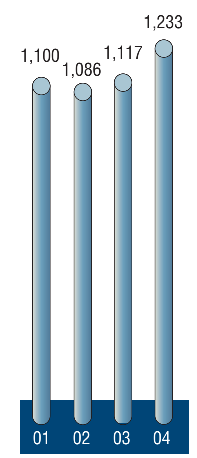
In Trinidad, EOG commenced natural gas sales to NGC for the N2000 ammonia plant in mid-2004. Also, we contracted to supply natural gas to NGC for both the M5000 methanol plant, which is scheduled to come on-line in July, and for an LNG plant beginning in mid-2006.

With significant opportunities throughout our operations, EOG's expected capital budget for 2005 is approximately $1.6 billion, excluding potential acquisitions, versus $1.5 billion spent in 2004.

EOG YEAR-END RESERVES
(Bcfe)



EOG DAILY PRODUCTION
(MMcfed)



The Dynamics of Performance

Barnett Shale Play

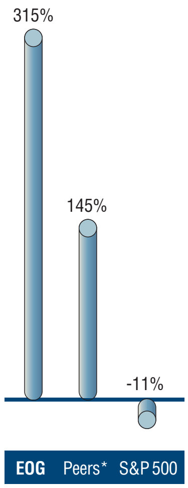
While EOG's Texas Barnett Shale play is creating excitement because of its potential scope and ability to generate high reinvestment rates of return for years to come, the company's worldwide operations have a very extensive drilling inventory.

The Technology of Performance

Roleta Trend

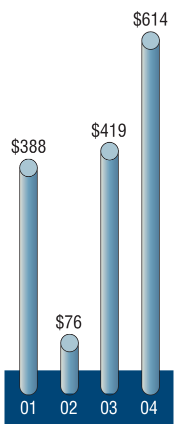
South Texas explorationists, Andy Scott (seated) and Dan Flores (standing), fuel EOG's penchant for 'growth through the drillbit' by generating exciting new drilling opportunities. After increasing total company production on a daily basis by 10.4 percent in 2004, EOG is targeting a 13.5 percent increase for 2005.

COMPARATIVE FIVE-YEAR RETURNS TO SHAREHOLDERS[1]
(2000 - 2004)



*AMEX Natural Gas Index

EOG NET INCOME AVAILABLE TO COMMON
(Millions)



Exemplary Shareholder Returns

While we are pleased about our 2004 performance, EOG's five-year return to shareholders[1] is truly more meaningful because it reflects company performance since we became independent. Between 2000 and 2004, EOG's return to shareholders was 315 percent. This compares favorably to a loss for both the S&P 500 and the Dow Jones Industrial Average during this same period. The average return to shareholders for our peer group during the period was 145 percent.

Clearly, EOG's out-performance of the S&P 500 and the Dow Jones Industrial Average is linked to rising natural gas and crude oil prices over the five-year period. However, the company's outstanding performance relative to its peer group cannot be attributed only to rising hydrocarbon prices because all exploration and production companies benefited from higher prices.

It's our belief that what has set EOG apart is the consistent focus on returns, measured by ROE and ROCE. Over the five-year period, 2000-2004, EOG averaged 23 percent ROE[1] and 15 percent ROCE[1] — significantly higher than our peer group average. Although exploration and production companies typically generate high levels of cash flow, companies that consistently reinvest that cash flow at high rates of return will have higher ROE and ROCE ratios over time. To reinforce our focus on achieving high returns throughout our organization, EOG's bonus plan is primarily allocated based on reinvestment rates of return.

North American Natural Gas Story Unfolds

EOG continues to view the North American natural gas market as tight, driven by declining domestic supply and increasing demand to produce electricity. Initial year decline rates in the United States have reached 50 percent with overall decline rates at 30 percent. Just to keep production flat, every year the United States natural gas industry must replace 30 percent of the previous year's total production. Even at full rig utilization, this has become extremely difficult. Thus, domestic production continues to decline. On the other hand, the demand for electricity has increased in 27 of the last 30 years. For many years to come, the increased demand for electricity will be met by natural gas-fired plants because few alternate sources — coal, nuclear or hydroelectric plants — are being constructed. Renewable energy sources, such as wind turbines, supply only a very small portion of the country's energy needs.

Our Commitment to the World Around Us

Our employees share the responsibility for EOG's commitment to excellence in health, safety and the environment. We have voluntarily adopted the member ethics of the Domestic Petroleum Council devoted to protecting land, air and water and have an outstanding operations safety record.

We continually seek ways to enhance the safety of our operations such as implementing a program to pinpoint the exact routes of our underground natural gas flow lines using global positioning satellite technology. Also, EOG annually recognizes noteworthy accomplishments of our employees with regard to environmental, health and safety practices. Last year this included an Oklahoma City team, which created an innovative spill-free system on a waterflood project that is increasing oil recovery from a mature reservoir.

EOG employees regularly provide leadership on the front lines of the communities in which they live and work. For example, for the fifth consecutive year, Houston employees donated gifts during the holiday season for children in crisis at Casa de Esperanza. EOG is a corporate sponsor of the Cactus & Crude MS 150 Bike Tour in Midland, and our employees are very involved in the March of Dimes WalkAmerica fundraising event in Corpus Christi. Across our operations, numerous other instances demonstrate our employees' respect and care for their neighbors and communities.

Looking Ahead

With the election of W. D. (Bill) Stevens and H. Leighton Steward to the EOG Board of Directors last year, EOG added two more experts from the exploration and production industry to oversee its activities. Bill Stevens, who has had a long career in the energy industry, most recently was president and chief operating officer of Mitchell Energy and Development Corporation. Another industry leader for decades, Leighton Steward served as vice chairman of Burlington Resources until his retirement.

Based on the strength of EOG's performance to date, we believe we have the employees, the assets and the game plan to steadily post superior shareholder returns for another five-year period and beyond. To reach our goal, we'll continue to focus on our long-term strategy that emphasizes financial returns, a strong balance sheet and organic production growth with a high reinvestment rate of return. We will rely on the proven performance of our operations in the United States, Canada and Trinidad, augmented by the new Texas Barnett Shale and North Sea discoveries, as we add other new plays to our portfolio. In all aspects of our business, we will strive for consistency because that is the foundation that underlies EOG.

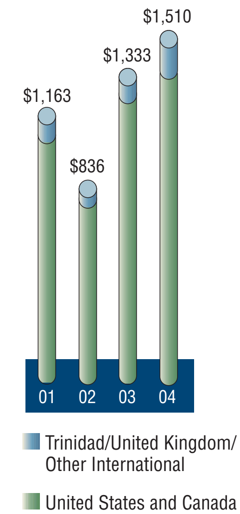
Mark G. Papa
Chairman and Chief Executive Officer

Edmund P. Segner, III
President and Chief of Staff

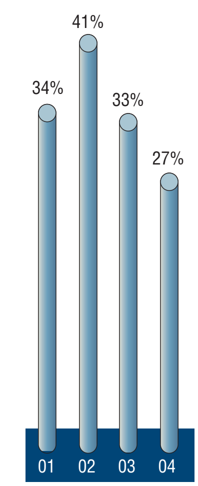
February 24, 2005

[1] Refer to reconciliation schedule on page 55.

EOG TOTAL EXPLORATION & DEVELOPMENT EXPENDITURES
(Millions)



EOG YEAR-END DEBT-TO-TOTAL CAPITALIZATION RATIO[1]



The Consistency of Performance

Canada

Repeatedly ranking as a low-cost operator, EOG places its talented professionals close to their respective areas of activity and responsibility. This strategy has proven successful across the company.

EOG OPERATIONS

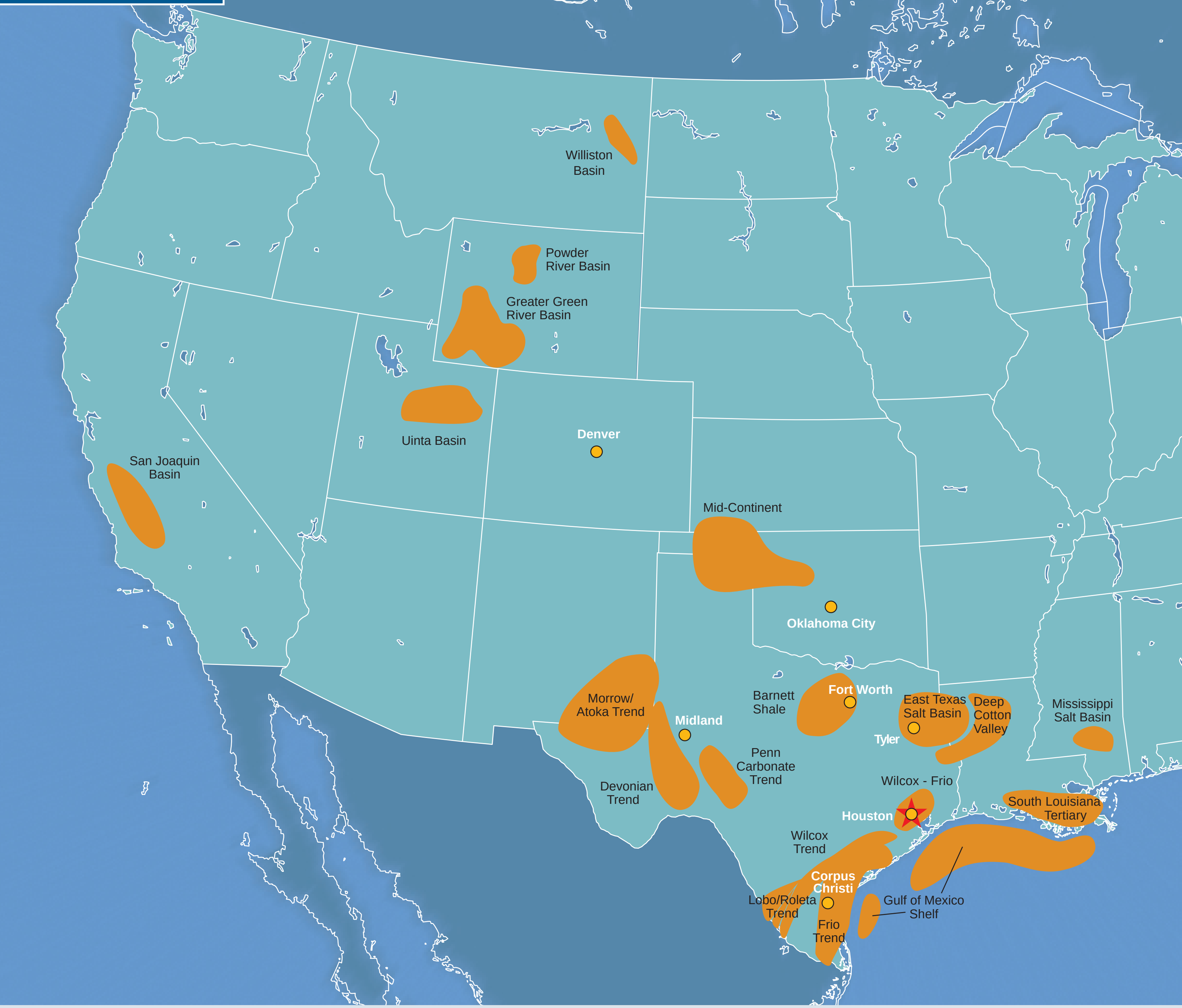
LEGEND

- Areas of Operation
- Offices
- Corporate Headquarters

WORLDWIDE

2004 Production	458 Bcfe
2004 Reserves	5,647 Bcfe

UNITED STATES

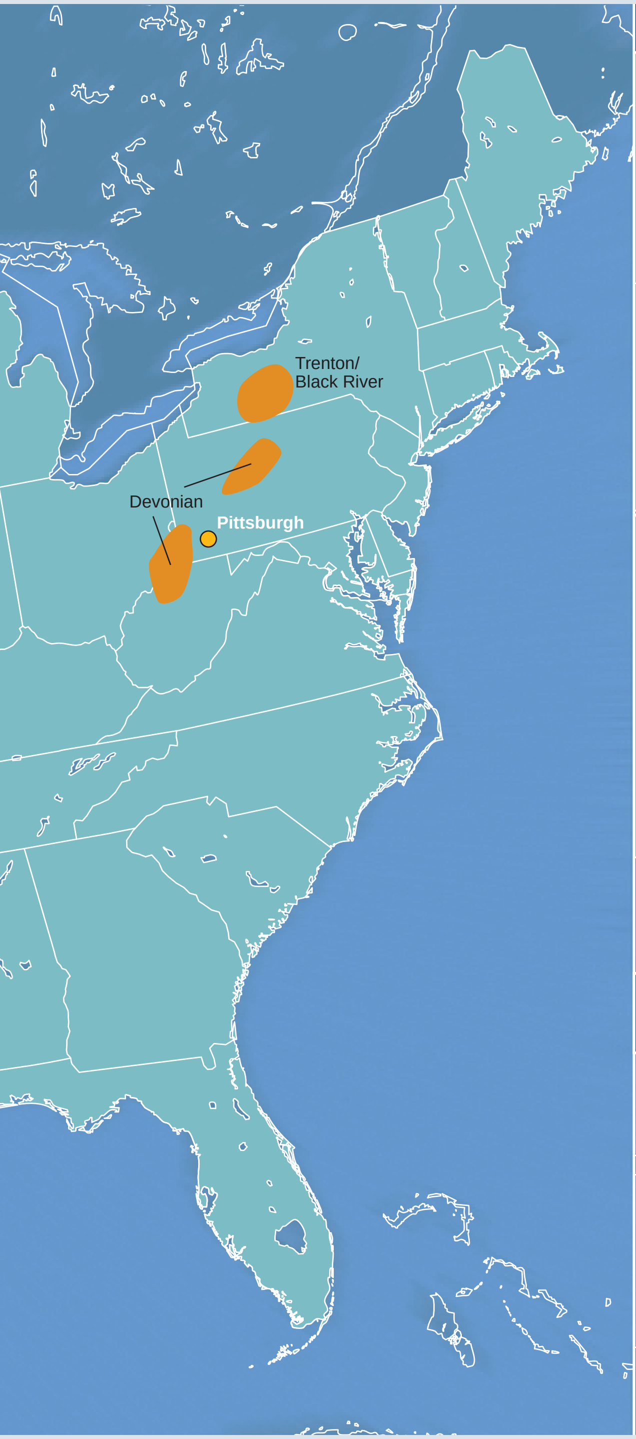


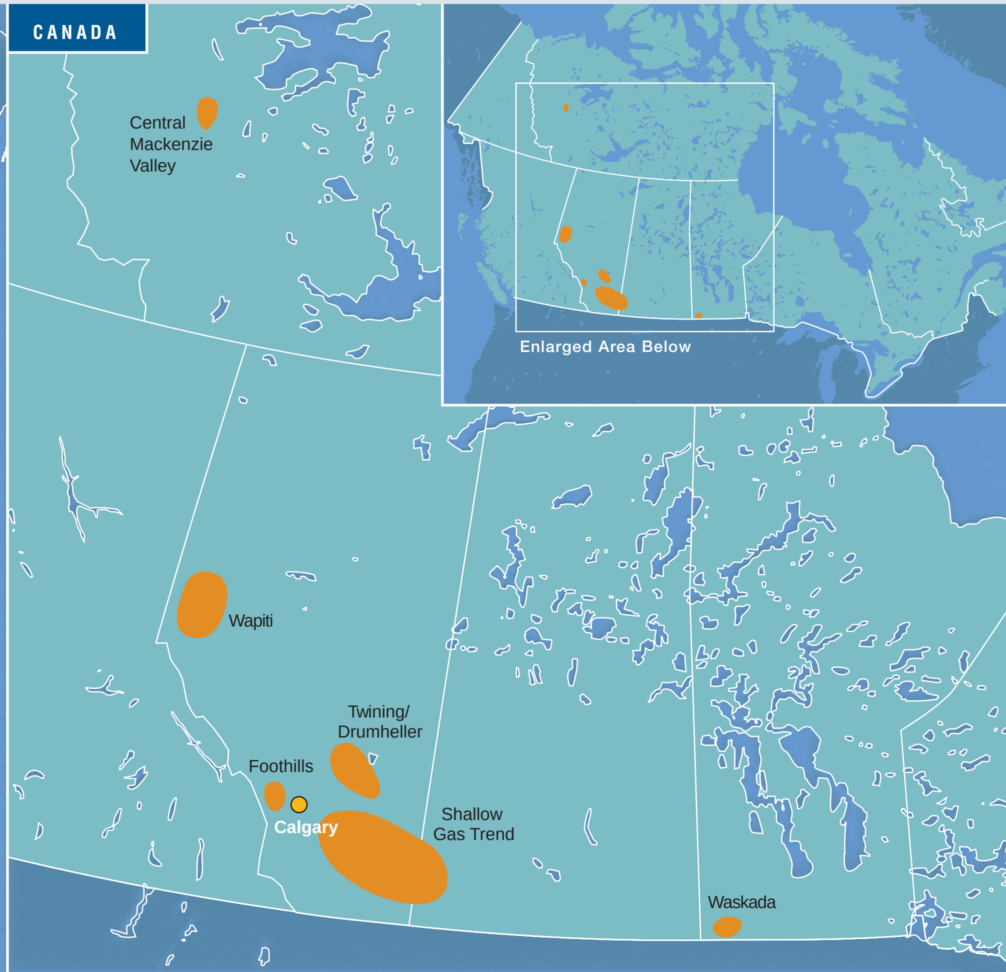
UNITED STATES

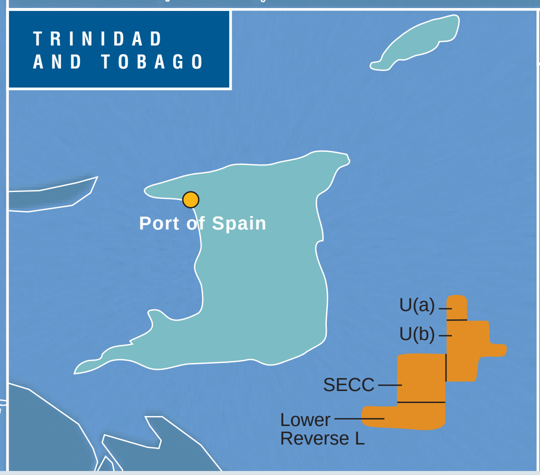
2004 Production	294 Bcfe
2004 Reserves	2,837 Bcfe

CANADA

2004 Production	85 Bcfe
2004 Reserves	1,345 Bcfe







TRINIDAD AND TOBAGO

2004 Production	76 Bcfe
2004 Reserves	1,407 Bcfe

UNITED KINGDOM

2004 Production	3 Bcfe
2004 Reserves	58 Bcfe

FINANCIAL REVIEW

OVERVIEW

EOG Resources, Inc. (EOG) is one of the largest independent (non-integrated) oil and natural gas companies in the United States with substantial proved reserves in the United States, Canada, offshore Trinidad and, to a lesser extent, the United Kingdom North Sea. EOG operates under a consistent business and operational strategy which focuses predominantly on achieving a strong reinvestment rate of return, drilling internally generated prospects, delivering long-term production growth and maintaining a strong balance sheet, with a below average debt-to-total capitalization ratio.

EOG had another year of record operating earnings in 2004. Net income available to common for 2004 of $614 million was up 47% over 2003 earnings of $419 million, attributable primarily to higher commodity prices and increased production. At December 31, 2004, EOG's total reserves were 5.6 Tcfe, an increase of 430 Bcfe, or 8% higher than 2003.

Operations

Several important developments have occurred since January 1, 2004.

United States and Canada. During 2004, EOG opened a new office in Fort Worth, Texas to expand its drilling success in the Barnett Shale play of the Fort Worth Basin. EOG made significant gas discoveries in the non-core portion of the trend located south and west of the City of Fort Worth. EOG plans to focus on increasing production and further defining the play's ultimate size during 2005.

EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG plans to continue to drill smaller wells in large acreage plays, which in the aggregate will contribute substantially to EOG's crude oil and natural gas production. EOG has several larger potential plays under way in Wyoming, Utah, Texas, Oklahoma and western Canada.

International. In mid-2004, EOG began natural gas sales to NGC under a fifteen-year take-or-pay contract. This gas is being resold by NGC to an anhydrous ammonia plant located in Point Lisas, Trinidad. The plant is owned by N2000. At December 31, 2004, EOG's subsidiary, EOG Resources NITRO2000 Ltd., owned an approximate 23% equity interest in N2000. Under the contract, EOG supplies approximately 60 MMcfd gross of natural gas to NGC.

Although EOG continues to focus on United States and Canada natural gas, EOG sees an increasing linkage between United States and Canada natural gas demand and Trinidadian natural gas supply. For example, LNG imports from existing and planned facilities in Trinidad are serious contenders to meet increasing United States demand. In addition, ammonia, methanol and chemical production has been relocating from the United States and Canada to Trinidad, driven by attractive natural gas feedstock prices in the island nation. EOG anticipates that its existing position with the supply contracts to the two ammonia plants and the new methanol plant, will continue to give its portfolio an even broader exposure to United States and Canada natural gas fundamentals.

In 2004, EOG continued its progress in the Southern Gas Basin of the United Kingdom North Sea. A development well was drilled in the Valkyrie field and commenced production in August 2004. In addition, the production facilities were installed in the Arthur field, which was discovered in 2003, and production commenced in January 2005. EOG continues to review additional opportunities in this area and expects to participate in several exploration wells in 2005.

Capital Structure

As noted, one of management's key strategies is to keep a strong balance sheet with a consistently below average debt-to-total capitalization ratio. At December 31, 2004, EOG's debt-to-total capitalization ratio was 27%, down from 33% at year-end 2003. By primarily utilizing cash provided from its operating activities and proceeds from stock options exercised in 2004, EOG funded its $1.5 billion exploration and development expenditures, paid down $31 million of debt, redeemed all 500 outstanding shares of Series D Preferred Stock for $50 million and increased the dividend paid to common shareholders by 20%. In addition, in 2005, EOG's Board of Directors increased the quarterly cash dividend on common stock by 33%. As management currently assesses price forecast and demand trends for 2005, EOG believes that operations and capital expenditure activity can essentially be funded by cash from operations.

For 2005, EOG's estimated exploration and development expenditure budget is approximately $1.6 billion, excluding acquisitions. United States and Canada natural gas continues to be a key component of this effort. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

RESULTS OF OPERATIONS

The following review of operations for each of the three years in the period ended December 31, 2004 should be read in conjunction with the consolidated financial statements of EOG and notes thereto.

Net Operating Revenues

During 2004, net operating revenues increased $527 million to $2,271 million. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids from producing wells, increased 27% to $2,301 million, as compared to $1,818 million in 2003. Natural Gas Revenues consists of natural gas wellhead revenues and revenues from marketing activities associated with the sales and purchases of natural gas. Revenues from natural gas marketing activities were $2 million for each of 2004 and 2003. Crude oil, condensate and natural gas liquids revenues represent solely wellhead revenues for these products. Wellhead volume and price statistics for the years ended December 31, were as follows:

	2004	2003	2002
Natural Gas Volumes (MMcf per day)			
United States	631	638	635
Canada	212	165	154
Trinidad	186	152	135
United Kingdom	7	-	-
Total	1,036	955	924
Average Natural Gas Prices ($/Mcf)			
United States	$ 5.72	$ 5.06	$ 2.89
Canada	5.22	4.66	2.67
Trinidad	1.51	1.35	1.20
United Kingdom	5.14	-	-
Composite	4.86	4.40	2.60
Crude Oil and Condensate Volumes (MBbl per day)			
United States	21.1	18.5	18.8
Canada	2.7	2.3	2.1
Trinidad	3.6	2.4	2.4
Total	27.4	23.2	23.3
Average Crude Oil and Condensate Prices ($/Bbl)			
United States	$ 40.73	$ 30.24	$24.79
Canada	37.68	28.54	23.62
Trinidad	39.12	28.88	23.58
Composite	40.22	29.92	24.56
Natural Gas Liquids Volumes (MBbl per day)			
United States	4.8	3.2	2.9
Canada	0.8	0.6	0.8
Total	5.6	3.8	3.7
Average Natural Gas Liquids Prices ($/Bbl)			
United States	$ 27.79	$ 21.53	$14.76
Canada	23.23	19.13	11.17
Composite	27.13	21.13	14.05
Natural Gas Equivalent Volumes (MMcfe per day)			
United States	786	768	765
Canada	233	183	171
Trinidad	207	166	150
United Kingdom	7	-	-
Total	1,233	1,117	1,086
Total Bcfe Deliveries	451.5	407.8	396.3

2004 compared to 2003. Wellhead natural gas revenues for 2004 increased $307 million, or 20%, to $1,842 million from $1,535 million for 2003 due to increases in natural gas deliveries ($134 million) and the composite average wellhead natural gas price ($173 million). The composite average wellhead natural gas price increased 10% to $4.86 per Mcf for 2004 from $4.40 per Mcf in 2003.

Natural gas deliveries increased 81 MMcf per day, or 8%, to 1,036 MMcf per day for 2004 from 955 MMcf per day in 2003, due to a 47 MMcf per day, or 28%, increase in Canada; a 34 MMcf per day, or 22%, increase in Trinidad; and a 7 MMcf per day increase in the United Kingdom due to commencement of production in August 2004, partially offset by a 7 MMcf per day, or 1% decline in the United States. The increased deliveries in Canada (47 MMcf per day) were attributable to property acquisitions completed in the fourth quarter of 2003 and additional production related to post acquisition drilling. The increase in Trinidad was attributable to the increased production from the U(a) block (22 MMcf per day), which began supplying natural gas in mid-2004 to the N2000 ammonia plant and commencement of production from the Parula wells on the SECC block in February 2004 (12 MMcf per day).

Wellhead crude oil and condensate revenues increased $149 million, or 59%, to $403 million from $254 million, as compared to 2003, due to increases in both the composite average wellhead crude oil and condensate price ($103 million) and the wellhead crude oil and condensate deliveries ($46 million). The composite average wellhead crude oil and condensate price for 2004 was $40.22 per barrel, compared to $29.92 per barrel for 2003.

Wellhead crude oil and condensate deliveries increased 4.2 MBbl per day, or 18%, to 27.4 MBbl per day from 23.2 MBbl per day for 2003. The increase was mainly due to production from new wells in the United States (2.6 MBbl per day) and higher production in Trinidad from the Parula wells (0.8 MBbl per day) and from the U(a) block as a result of new production (0.4 MBbl per day).

Natural gas liquids revenues were $26 million higher than a year ago primarily due to increases in deliveries ($14 million) and the composite average price ($12 million).

During 2004, EOG recognized losses on mark-to-market commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. During 2003, EOG recognized losses on mark-to-market commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million.

2003 compared to 2002. Wellhead natural gas revenues for 2003 increased $657 million, or 75%, due to increases in the composite average wellhead natural gas price and natural gas deliveries. The composite average wellhead price for natural gas increased 69% to $4.40 per Mcf for 2003 from $2.60 per Mcf in 2002.

Natural gas deliveries increased to 955 MMcf per day for 2003 from 924 MMcf per day for the comparable period in 2002. The overall increase in natural gas deliveries was primarily due to an increase in Canada of 7% to 165 MMcf per day and an increase in Trinidad of 13% to 152 MMcf per day in 2003. The 7%, or 11 MMcf per day, increase in Canada was primarily attributable to a major property acquisition in the fourth quarter. The 13%, or 17 MMcf per day, increase in Trinidad was attributable to a full year of sales to the CNCL ammonia plant versus only six months of sales in 2002.

Natural gas marketing activities increased natural gas revenues by $2 million and $37 million for 2003 and 2002, respectively.

Wellhead crude oil and condensate revenues increased $45 million, or 22%, due to increases in the composite average wellhead crude oil and condensate price. The composite average wellhead crude oil and condensate price for 2003 was $29.92 per barrel, compared to $24.56 per barrel for 2002.

Natural gas liquids revenues were $11 million higher than a year ago primarily due to a 50% increase in the composite average price and a 3% increase in deliveries.

During 2003, EOG recognized losses on mark-to-market commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million. During 2002, EOG recognized losses on mark-to-market commodity derivative contracts of $49 million, which included realized losses of $21 million and a $2 million collar premium payment.

Operating and Other Expenses

2004 compared to 2003. During 2004, operating expenses of $1,292 million were $245 million higher than the $1,047 million incurred in 2003. The following table presents the costs per Mcfe for the years ended December 31:

	2004	2003
Lease and Well, including Transportation	**$ 0.60**	$ 0.52
DD&A	**1.12**	1.08
G&A	**0.25**	0.25
Taxes Other than Income	**0.30**	0.21
Interest Expense, Net	**0.14**	0.14
Total Per-Unit Costs	**$ 2.41**	$ 2.20

The higher per-unit rates of lease and well, DD&A and taxes other than income for 2004 compared to 2003 were due primarily to the reasons set forth below.

Lease and well expenses of $271 million were $58 million higher than 2003 due primarily to a general increase in service costs related to increased operating activities, including an increase in the number of wells, in the United States ($18 million), Canada ($16 million), and Trinidad ($1 million); increased transportation related costs in the United States ($14 million), Canada ($2 million) and the United Kingdom ($2 million); and changes in the Canadian exchange rate ($5 million).

Depreciation, depletion and amortization (DD&A) expenses of $504 million increased $63 million from 2003 due primarily to increased production in Canada ($18 million), the United States ($10 million), and Trinidad ($4 million); the commencement of production in the United Kingdom ($2 million); increased DD&A rates in the United States due to a gradual proportional increase in production from higher cost properties ($13 million); increased DD&A rates in Canada mainly from developing acquired proved reserves ($8 million); and changes in the Canadian exchange rate ($7 million).

General and administrative (G&A) expenses of $115 million were $15 million higher than 2003 due primarily to expanded operations.

Taxes other than income of $134 million were $48 million higher than 2003 due primarily to a decrease in credits taken against severance taxes resulting from the qualification of additional wells for a Texas high cost gas severance tax exemption ($19 million); an increase as a result of higher wellhead revenues in the United States ($13 million), Trinidad ($2 million) and Canada ($1 million); higher property taxes as a result of higher property valuation in the United States ($6 million); the results of a production tax audit lawsuit in the first quarter of 2004 ($5 million); and an increase in the number of wells and facilities in Canada ($2 million).

Exploration costs of $94 million were $18 million higher than 2003 due primarily to increased geological and geophysical expenditures in the United States ($6 million), Canada ($3 million), the United Kingdom ($3 million) and Trinidad ($1 million); and increased exploration administrative expenses across EOG ($4 million).

Impairments of $82 million were $8 million lower than 2003 due primarily to lower amortization of unproved leases in the United States ($10 million), partially offset by higher amortization of unproved leases in Canada ($2 million). Total impairments under Statement of Financial Accounting Standards (SFAS) No. 144 - “Accounting for the Impairment or Disposal of Long-Lived Assets” were $25 million in each of 2004 and 2003.

Net interest expense of $63 million was $4 million higher than 2003 due primarily to a slightly higher average debt balance.

Other Income (Expense), Net for 2004 included income from equity investments of $11 million, gains on sales of reserves and related assets of $6 million and foreign currency transaction losses of $7 million as a result of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation.

Income tax provision increased $85 million to $301 million compared to 2003, primarily resulting from higher income before income taxes ($95 million) and an increase in state income taxes ($2 million), offset by lower deferred income taxes associated with the Alberta, Canada corporate tax rate ($5 million) and lower effective foreign income tax rates ($2 million). As a result of these changes, the net effective tax rate for 2004 remained unchanged from the 2003 rate of 33%.

In November 2003, Canada enacted legislation reducing the Canadian federal income tax rate for companies in the resource sector from 28% to 27% for 2003, with further reductions to 21% phased in over the next four years. This legislation also made changes to the tax treatment of crown royalties and the resource allowance. Beginning in 2003, Canadian taxpayers are allowed to deduct 10% of actual provincial and other crown royalties. This percentage increases each year through 2007, at which time 100% of crown royalties will be deductible. The resource allowance, a statutory deduction calculated as 25% of adjusted resource profits, will be phased out through 2007, when the deduction will be completely eliminated.

2003 compared to 2002. During 2003, operating expenses of $1,047 million were $133 million higher than the $914 million incurred in 2002. The following table presents the costs per Mcfe for the years ended December 31:

	2003	2002
Lease and Well, including Transportation	$ 0.52	$ 0.45
DD&A	1.08	1.00
G&A	0.25	0.22
Taxes Other than Income	0.21	0.18
Interest Expense, Net	0.14	0.15
Total Per-Unit Costs	$ 2.20	$ 2.00

The higher per-unit rates of lease and well, DD&A, G&A and taxes other than income for 2003, compared to 2002 were due primarily to the reasons set forth below.

Lease and well expenses of $213 million were $33 million higher than 2002 due primarily to a general increase in service costs related to increased operating activities, including an increase in the number of wells, in the United States ($15 million) and Canada ($4 million); increased lease and well administrative expenses in the United States ($7 million); and changes in the Canadian exchange rate ($6 million).

DD&A expenses of $442 million increased $44 million from the prior year due primarily to more relative production from higher cost properties in the United States ($20 million) and Canada ($5 million); increased production in Canada ($3 million) and Trinidad ($2 million); and changes in the Canadian exchange rate ($8 million). Also, included in DD&A expenses for 2003 was $5 million of accretion expense related to SFAS No. 143 - “Accounting for Asset Retirement Obligations.”

G&A expenses of $100 million were $11 million higher than the period a year ago due primarily to expanded operations ($9 million) and increased insurance expense ($5 million), partially offset by decreased legal costs ($3 million).

Taxes other than income of $86 million were $14 million higher than the prior year period primarily due to an increase of approximately $35 million as a result of increased wellhead revenues as previously discussed, partially offset by $24 million of severance tax credits from the qualification of wells for a Texas high cost gas severance tax exemption.

Exploration costs of $76 million were $16 million higher than a year ago due primarily to an increase in technical staff costs across EOG ($7 million) and increased geological and geophysical expenditures in the United States ($5 million) and Trinidad ($3 million).

Impairments increased $21 million to $89 million compared to a year ago due to higher amortization of unproved leases in the United States ($25 million). Total impairments under SFAS No. 144 - "Accounting for the Impairment or Disposal of Long-Lived Assets" for 2003 and 2002 were $25 million and $30 million, respectively.

Other Income (Expense), Net for 2003 included foreign currency transaction gains of $9 million as a result of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation and income from equity investments of $4 million.

Income tax provision increased $184 million to $217 million for 2003 as compared to 2002 primarily resulting from higher income before income taxes for federal ($187 million) and state ($4 million), expiration of the tight gas sands federal income tax credit as of December 31, 2002 ($4 million), and higher effective foreign income tax rates ($4 million), primarily offset by net tax benefit associated with the Canadian tax law change ($14 million).

CAPITAL RESOURCES AND LIQUIDITY

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2004 included funds generated from operations, funds from new borrowings and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan. Primary cash outflows included funds used in operations, exploration and development expenditures, oil and gas property acquisitions, repayment of debt, redemption of preferred stock, common stock repurchases and dividends.

2004 compared to 2003. Net operating cash inflows of $1,444 million in 2004 increased $195 million, as compared to 2003 primarily reflecting an increase in wellhead revenues of $482 million, partially offset by an increase in cash operating expenses of $139 million, an increase in current tax expense of $72 million, unfavorable changes in working capital and other liabilities of $48 million and an increase in realized losses from mark-to-market commodity derivative contracts of $38 million.

Net investing cash outflows of $1,397 million in 2004 increased by $189 million, as compared to 2003 due primarily to increased additions to oil and gas properties of $171 million and unfavorable changes in working capital related to investing activities of $12 million. Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used by financing activities was $43 million in 2004 versus $57 million in 2003. Cash provided by financing activities for 2004 included long-term debt borrowing of $150 million and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan of $76 million. Cash used by financing activities for 2004 included repayments of long-term debt borrowings of $175 million, redemption of all 500 outstanding shares of Series D Preferred Stock of $50 million and cash dividend payments of $38 million.

2003 compared to 2002. Net operating cash inflows of $1,249 million in 2003 increased $638 million, as compared to 2002 primarily reflecting an increase wellhead commodity revenues of $713 million and favorable changes in working capital and other liabilities of $117 million, partially offset by an increase in cash operating expenses of $75 million, an increase in current tax expense of $75 million and an increase in realized losses from mark-to-market commodity derivative contracts of $24 million.

Net investing cash outflows of $1,207 million in 2003 increased by $391 million as compared to 2002 due primarily to increased additions to oil and gas properties of $485 million, which includes $366 million related to two Canadian asset purchases, partially offset by favorable changes in working capital related to investing activities of $82 million. Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used by financing activities was $57 million in 2003 versus cash provided of $211 million in 2002. Financing activities for 2003 included repayment of the outstanding balances of commercial paper borrowings and the uncommitted line of credit of $22 million and $14 million, respectively, repurchases of EOG's common stock of $21 million, cash dividend payments of $31 million and proceeds of $35 million from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan.

Exploration and Development Expenditures

The table below sets out components of exploration and development expenditures for the years ended December 31, 2004, 2003 and 2002, along with the total budgeted for 2005, excluding acquisitions (in millions):

Expenditure Category	Actual 2004	Actual 2003	Actual 2002	Budgeted 2005 (excluding acquisitions)
Capital				
Drilling and Facilities	**$ 1,120**	$ 731	$ 595	
Leasehold Acquisitions	**143**	59	39	
Producing Property Acquisitions	**52**	405	71	
Capitalized Interest	**10**	9	9	
Subtotal	**1,325**	1,204	714	
Exploration Costs	**94**	76	60	
Dry Hole Costs	**92**	41	47	
Exploration and Development Expenditures	**1,511**	1,321	821	Approximately $1,600
Asset Retirement Costs(1)	**16**	12	-	
Deferred Income Tax on Acquired Properties	**(17)**	-	15	
Total(2)	**$ 1,510**	$ 1,333	$ 836	

(1) The Asset Retirement Costs are netted with $1 million net gains recognized upon settlement of asset retirement obligations for each of 2004 and 2003. Asset Retirement Costs for 2003 does not include the cumulative effect of adoption of SFAS No. 143 - "Accounting for Asset Retirement Obligations" on January 1, 2003.

(2) Pro forma total expenditures for 2002 are not presented since the pro forma application of SFAS No. 143 to the prior periods would not result in pro forma total expenditures materially different from the actual amounts reported.

Exploration and development expenditures of $1.5 billion for 2004 were $190 million higher than the prior year due primarily to increased drilling expenditures ($439 million) resulting from higher exploration and development activities in Canada and Trinidad and higher cost structures in the United States and Canada; increased lease acquisitions in the United States ($84 million), primarily in the non-core Barnett Shale area and, to a lesser extent, in South Texas; and changes in the Canadian exchange rate ($20 million); partially offset by decreased property acquisitions ($353 million). The higher cost structure was primarily due to increases in materials and services across the industry. The 2004 exploration and development expenditures of $1.5 billion includes $1,009 million in development, $440 million in exploration, $52 million in property acquisitions and $10 million in capitalized interest. The 2003 exploration and development expenditures of $1,321 million included $651 million in development, $256 million in exploration, $405 million in property acquisitions and $9 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. There are no material continuing commitments associated with current expenditure plans.

Derivative Transactions

During 2004, EOG recognized losses on mark-to-market commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. During 2003, EOG recognized losses on mark-to-market commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million. (See Note 11 to the Consolidated Financial Statements.)

Presented below is a summary of EOG's 2005 natural gas financial collar contracts at February 25, 2005. As indicated, EOG does not have any financial collar or swap contracts that cover periods beyond March 2005. Moreover, EOG has not entered into any additional natural gas financial collar contracts or natural gas or crude oil financial price swap contracts since December 31, 2004. EOG accounts for these collar and swap contracts using mark-to-market accounting.

	Natural Gas Financial Collar Contracts					
		Floor Price		Ceiling Price		
2005	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)	Settlement Price ($/MMBtu)
Jan(1)	75,000	$7.65 - 8.00	$7.77	$8.90 - 9.50	$9.10	$6.35
Feb(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.36
Mar(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32	6.24

(1) Notional volumes of 25,000 MMBtud of the January 2005 collar contracts were purchased at a premium of $0.10 per MMBtu.

(2) The collar contracts for February 2005 and March 2005 were purchased at a premium of $0.10 per MMBtu.

Financing

EOG's long-term debt-to-total capitalization ratio was 27% as of December 31, 2004, compared to 33% as of December 31, 2003.

During 2004, total long-term debt decreased $31 million to $1,078 million (see Note 2 to the Consolidated Financial Statements). The estimated fair value of EOG's long-term debt at December 31, 2004 and 2003 was $1,146 million and $1,175 million, respectively, based upon quoted market prices and, where such prices were not available, upon interest rates currently available to EOG at year-end. EOG's debt is primarily at fixed interest rates. At December 31, 2004, a 1% decline in interest rates would result in a $59 million increase in the estimated fair value of the fixed rate obligations (see Note 11 to the Consolidated Financial Statements).

During 2004, EOG utilized commercial paper, and during 2003, EOG utilized commercial paper and committed bank loans, in addition to operating cash flows, to fund its operations. These loans are more fully described in Note 2 to the Consolidated Financial Statements. While EOG maintains a $600 million commercial paper program, the maximum outstanding at any time during 2004 was $321 million, and the amount outstanding at year-end was $92 million. EOG considers this excess availability, which is contractually backed by the $600 million Revolving Credit Agreement with domestic and foreign lenders described in Note 2, combined with the $688 million of availability under its shelf registration described below, to be ample to meet its ongoing operating needs.

Based on resources available at December 31, 2004, during 2005, EOG plans to replace the Senior Unsecured Term Loan Facility due 2005 with long-term debt. In 2004, the short-term commercial paper loan balance was reduced ($6 million) and the $100 million, 6.50% Notes were paid off by long-term debt refinancing.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2004 (in thousands):

Contractual Obligations(1)	Total	2005	2006 - 2008	2009 - 2010	2011 & Beyond
Long-Term Debt(2)	$ 1,077,622	$ 166,800	$ 400,822	$ -	$ 510,000
Non-cancelable Operating Leases	45,784	13,497	20,934	5,594	5,759
Drilling Rig Commitments	2,214	1,142	1,072	-	-
Pipeline Transportation Service Commitments(3)	128,983	21,697	49,518	19,139	38,629
Seismic Purchase Obligations	7,904	7,904	-	-	-
Other Purchase Obligations	2,918	1,628	1,290	-	-
Total Contractual Obligations	$ 1,265,425	$ 212,668	$ 473,636	$ 24,733	$ 554,388

(1) This table does not include the liability for dismantlement, abandonment and restoration costs of oil and gas properties. Effective with adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003, EOG recorded a separate liability for the fair value of this asset retirement obligation. See Note 13 to the Consolidated Financial Statements. In addition, this table does not include EOG's pension or postretirement benefit obligations. See Note 6 to the Consolidated Financial Statements.

(2) Commercial paper and the Senior Unsecured Term Loan Facility due 2005 are classified as long-term debt on the Consolidated Balance Sheets based on EOG's intent and ability to ultimately replace such amounts with other long-term debt. See Note 2 to the Consolidated Financial Statements.

(3) Amounts shown are based on current pipeline transportation rates and the Canadian foreign currency exchange rate at December 31, 2004. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results of operations of EOG.

Shelf Registration

As of February 25, 2005, the amount available under various filed registration statements with the Securities and Exchange Commission for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock totaled $688 million.

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities, often referred to as variable interest entities (VIE) or special purpose entities (SPE), are generally established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions during any of the reporting periods in this document and has no intention to participate in such transactions in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2004, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad and the United Kingdom. The foreign currency most significant to EOG's operations during 2004 was the Canadian Dollar. While the continued strengthening of the Canadian Dollar in 2004 impacted both the revenues and expenses recorded on the income statements of EOG's Canadian subsidiaries, its impacts on the items were not to the same extent. Since the Canadian natural gas prices are largely correlated to United States prices, the changes in the Canadian currency exchange rate have less of an impact on the Canadian revenues than the Canadian expenses. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against the foreign currency exchange rate risk.

Effective March 9, 2004, EOG entered into a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the notes offered by one of the Canadian subsidiaries on the same date (see Note 2 to the Consolidated Financial Statements). EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of SFAS No. 133 - "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. Under those provisions, as of December 31, 2004, EOG recorded the fair value of the swap of $23.1 million in Other Liabilities in the Liabilities section of the Consolidated Balance Sheets. Changes in the fair value of the foreign currency swap resulted in no net impact to the Consolidated Statements of Income. The after-tax net impact from the foreign currency swap transaction resulted in a negative change of $3.8 million for the year ended December 31, 2004. This amount is included in Accumulated Other Comprehensive Income in the Shareholders' Equity section of the Consolidated Balance Sheets.

Outlook

Natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of future United States and Canada natural gas and crude oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. In EOG's opinion, overall natural gas production in the United States is declining. In addition, the increasing recognition of natural gas as a more environmentally friendly source of energy is likely to result in increases in demand. Being primarily a natural gas producer, EOG is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate prices. Longer term natural gas prices will be determined by the supply and demand for natural gas as well as the prices of competing fuels, such as oil and coal.

Assuming a totally unhedged position for 2005, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2005 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in average wellhead natural gas price is approximately $21 million for net income and operating cash flow. EOG is not impacted as significantly by changing crude oil price. EOG's price sensitivity for each $1.00 per barrel change in average wellhead crude oil prices is approximately $6.5 million for net income and operating cash flow. For information regarding EOG's natural gas hedge position as of December 31, 2004, see Note 11 to the Consolidated Financial Statements.

Marketing companies have played an important role in the United States and Canada natural gas market. These companies aggregate natural gas supplies through purchases from producers like EOG and then resell the gas to end users, local distribution companies or other buyers. In recent years, several of the largest natural gas marketing companies have filed for bankruptcy or are having financial difficulty, and others are exiting this business. EOG does not believe that this will have a material effect on its ability to market its natural gas production. EOG continues to assess and monitor the credit worthiness of partners to whom it sells its production and where appropriate, to seek new markets.

EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States and Canada. However, in order to diversify its overall asset portfolio and as a result of its overall success realized in Trinidad and the United Kingdom North Sea, EOG anticipates expending a portion of its available funds in the further development of opportunities outside the United States and Canada. In addition, EOG expects to conduct exploratory activity in other areas outside of the United States and Canada and will continue to evaluate the potential for involvement in other exploitation type opportunities. Budgeted 2005 exploration and development expenditures, excluding acquisitions, are approximately $1.6 billion and are structured to maintain the flexibility necessary under EOG's strategy of funding the United States and Canada exploration, exploitation, development and acquisition activities primarily from available internally generated cash flow.

The level of exploration and development expenditures may vary in 2005 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, EOG believes net operating cash flow and available financing alternatives in 2005 will be sufficient to fund its net investing cash requirements for the year. However, EOG has significant flexibility with respect to its financing alternatives and adjustment of its exploration, exploitation, development and acquisition expenditure plans if circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad and the United Kingdom, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Environmental Regulations

Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to protection of the environment, affect EOG's operations and costs as a result of their effect on natural gas and crude oil exploration, development and production operations and could cause EOG to incur remediation or other corrective action costs in connection with a release of regulated substances, including crude oil, into the environment. In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG owns an interest but is not the operator. Compliance with such laws and regulations increases EOG's overall cost of business, but has not had a material adverse effect on EOG's operations or financial condition. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts that are material in relation to its total exploration and development expenditure program in order to comply with environmental laws and regulations but, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance. EOG also could incur costs related to the clean up of sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such sites.

SUMMARY OF CRITICAL ACCOUNTING POLICIES

EOG prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States of America, which requires management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. EOG identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of EOG's financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of EOG's most critical accounting policies:

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves, which directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas 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. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. Exploratory drilling costs are capitalized when drilling is complete if it is determined that there is economic producibility supported by either actual production, a conclusive formation test or by certain technical data if the discovery is located offshore in the Gulf of Mexico. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found due to the requirement of a significant capital investment. Such exploratory drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify development when the investment is made and additional exploratory wells are either in progress or firmly planned. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2004 and 2003, EOG had exploratory drilling costs of $4.3 million and $4.5 million, respectively, related to an outside operated, deepwater offshore Gulf of Mexico discovery that has been deferred for more than one year and will require significant future capital expenditures before production can commence. These costs meet the accounting requirements outlined above for continued capitalization. As of December 31, 2004 and 2003, there were no material exploratory drilling costs capitalized for more than one year for projects that did not require a major capital investment. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of natural gas and crude oil, are capitalized.

When circumstances indicate that an asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets are depreciated on a straight-line basis.

Assets are grouped in accordance with paragraph 30 of SFAS No. 19. The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions, and 4) impairments.

Stock Options

EOG accounts for stock options under the provisions and related interpretations of Accounting Principles Board (APB) Opinion No. 25 - "Accounting for Stock Issued to Employees." No compensation expense is recognized for such options. As allowed by SFAS No. 123 - "Accounting for Stock-Based Compensation" issued in 1995, EOG has continued to apply APB Opinion No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123.

In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148. SFAS No. 123(R), establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25. SFAS No. 123(R) will be effective for interim or annual reporting periods beginning on or after June 15, 2005. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 using the modified prospective method. EOG expects that the adoption of SFAS No. 123(R) would reduce second half 2005 net earnings by a pre-tax amount of approximately $10 million, which includes approximately $0.5 million for the Employee Stock Purchase Plan. SFAS No. 123(R) also requires a public entity to present its cash flows provided by tax benefits from stock options exercised in the Financing Cash Flows section of the Statement of Cash Flows. Had SFAS No. 123(R) been in effect, EOG's Net Cash Provided by Operating Activities would have been reduced and its Net Cash Provided by Financing Activities would have been increased on its Consolidated Statements of Cash Flows by $29 million, $12 million and $5 million for 2004, 2003 and 2002, respectively.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This 2004 Annual Report to Shareholders includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical facts, including, among others, statements regarding EOG's future financial position, business strategy, budgets, reserve information, projected levels of production, projected costs and plans and objectives of management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "strategy," "intend," "plan," "target" and "believe" or the negative of those terms or other variations of them or by comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning future operating results, the ability to replace or increase reserves or to increase production, or the ability to generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes its expectations reflected in forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will be achieved. Important factors that could cause actual results to differ materially from the expectations reflected in the forward-looking statements include, among others: the timing and extent of changes in commodity prices for crude oil, natural gas and related products, foreign currency exchange rates and interest rates; the timing and impact of liquefied natural gas imports and changes in demand or prices for ammonia or methanol; the extent and effect of any hedging activities engaged in by EOG; the extent of EOG's success in discovering, developing, marketing and producing reserves and in acquiring oil and gas properties; the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise; the availability and cost of drilling rigs, experienced drilling crews and tubular steel; the availability of pipeline transportation capacity; the extent to which EOG can replicate on its other Barnett Shale acreage the results of its most recent Barnett Shale wells; the results of wells yet to be drilled that are necessary to test whether substantial Barnett Shale acreage positions outside of Johnson and Parker Counties, Texas, contain suitable drilling prospects; whether EOG is successful in its efforts to more densely develop its acreage in the Barnett Shale and other production areas; political developments around the world; acts of war and terrorism and responses to these acts; and financial market conditions. In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements might not occur. EOG undertakes no obligations to update or revise its forward-looking statements, whether as a result of new information, future events or otherwise.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc. and its subsidiaries (EOG) were prepared by management, which is responsible for their integrity, objectivity and fair presentation. The statements have been prepared in conformity with generally accepted accounting principles and, accordingly, include some amounts that are based on the best estimates and judgments of management.

EOG's management is also responsible for establishing and maintaining effective internal control over financial reporting. The system of internal control of EOG is 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. This system consists of: 1) entity level controls, including written policies and guidelines relating to the ethical conduct of business affairs, 2) general computer controls and 3) process controls over initiating, authorizing, recording, processing and reporting transactions. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions.

The adequacy of financial controls of EOG and the accounting principles employed in financial reporting by EOG are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of EOG. The independent public accountants and internal auditors have full, free, separate and direct access to the Audit Committee and meet with the committee from time to time to discuss accounting, auditing and financial reporting matters.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2004. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment, management believes that, as of December 31, 2004, EOG's internal control over financial reporting is effective based on those criteria.

Deloitte & Touche LLP, independent public accountants, was engaged to audit the consolidated financial statements and management's assessment of the effectiveness of EOG's internal control over financial reporting, and to issue a report thereon. In the conduct of the audit, Deloitte & Touche LLP was given unrestricted access to all financial records and related data including minutes of all meetings of shareholders, the Board of Directors and committees of the Board. Management believes that all representations made to Deloitte & Touche LLP during the audit were valid and appropriate. Their audit was made in accordance with standards of the Public Company Accounting Oversight Board (United States) and included a review of the system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on the consolidated financial statements, management's assessment of EOG's internal control over financial reporting and the effectiveness of EOG's internal control over financial reporting. Their report appears on page 23.

Mark G. Papa

MARK G. PAPA
Chairman of the Board and Chief Executive Officer

Edmund P. Segner III

EDMUND P. SEGNER, III
President and Chief of Staff

TIMOTHY K. DRIGGERS
Vice President and Chief Accounting Officer

Houston, Texas
February 24, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
EOG Resources, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income and comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. We also have audited management's assessment, included in the accompanying Management's Responsibility for Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment, and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2005

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(In Thousands, Except Per Share Amounts)	Year Ended December 31 2004	2003	2002
Net Operating Revenues			
Natural Gas	$ 1,843,895	$ 1,537,352	$ 915,129
Crude Oil, Condensate and Natural Gas Liquids	458,446	283,042	227,309
Losses on Mark-to-Market Commodity Derivative Contracts	(33,449)	(80,414)	(48,508)
Other, Net	2,333	4,695	752
Total	2,271,225	1,744,675	1,094,682
Operating Expenses			
Lease and Well, including Transportation	271,086	212,601	179,429
Exploration Costs	93,941	76,358	60,228
Dry Hole Costs	92,142	41,156	46,749
Impairments	81,530	89,133	68,430
Depreciation, Depletion and Amortization	504,403	441,843	398,036
General and Administrative	115,013	100,403	88,952
Taxes Other Than Income	133,915	85,867	71,881
Total	1,292,030	1,047,361	913,705
Operating Income	979,195	697,314	180,977
Other Income (Expense), Net	9,945	15,273	(1,651)
Income Before Interest Expense and Income Taxes	989,140	712,587	179,326
Interest Expense			
Incurred	72,759	67,252	68,641
Capitalized	(9,631)	(8,541)	(8,987)
Net Interest Expense	63,128	58,711	59,654
Income Before Income Taxes	926,012	653,876	119,672
Income Tax Provision	301,157	216,600	32,499
Net Income Before Cumulative Effect of Change in Accounting Principle	624,855	437,276	87,173
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(7,131)	-
Net Income	624,855	430,145	87,173
Preferred Stock Dividends	10,892	11,032	11,032
Net Income Available to Common	$ 613,963	$ 419,113	$ 76,141
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.25	$ 3.72	$ 0.66
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(0.06)	-
Net Income Available to Common	$ 5.25	$ 3.66	$ 0.66
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 5.15	$ 3.66	$ 0.65
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	-	(0.06)	-
Net Income Available to Common	$ 5.15	$ 3.60	$ 0.65
Average Number of Common Shares			
Basic	116,876	114,597	115,335
Diluted	119,188	116,519	117,245
Comprehensive Income			
Net Income	$ 624,855	$ 430,145	$ 87,173
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustment	77,925	123,811	4,315
Foreign Currency Swap Transaction, Net of Income Tax Benefit of $1,972	(3,844)	-	-
Available-for-Sale Security Transactions	-	-	926
Comprehensive Income	$ 698,936	$ 553,956	$ 92,414

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

CONSOLIDATED BALANCE SHEETS

(In Thousands, Except Share Data)	At December 31 2004	2003
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 20,980	$ 4,443
Accounts Receivable, Net	447,742	295,118
Inventories	40,037	21,922
Assets from Price Risk Management Activities	10,747	-
Income Taxes Receivable	3,232	7,976
Deferred Income Taxes	22,227	31,548
Other	41,838	35,007
Total	586,803	396,014
Oil and Gas Properties (Successful Efforts Method)	9,599,276	8,189,062
Less: Accumulated Depreciation, Depletion and Amortization	(4,497,673)	(3,940,145)
Net Oil and Gas Properties	5,101,603	4,248,917
Other Assets	110,517	104,084
Total Assets	$ 5,798,923	$ 4,749,015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 424,581	$ 282,379
Accrued Taxes Payable	51,116	33,276
Dividends Payable	7,394	6,175
Liabilities from Price Risk Management Activities	-	37,779
Deferred Income Taxes	103,933	73,611
Other	45,180	43,299
Total	632,204	476,519
Long-Term Debt	1,077,622	1,108,872
Other Liabilities	241,319	171,115
Deferred Income Taxes	902,354	769,128
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series B, 100,000 Shares Issued, Cumulative, $100,000,000 Liquidation Preference	98,826	98,589
Series D, 500 Shares Issued, Cumulative, $50,000,000 Liquidation Preference	-	49,827
Common Stock, $.01 Par, 320,000,000 Shares Authorized and 124,730,000 Shares Issued	201,247	201,247
Additional Paid in Capital	21,047	1,625
Unearned Compensation	(29,861)	(23,473)
Accumulated Other Comprehensive Income	148,015	73,934
Retained Earnings	2,706,845	2,121,214
Common Stock Held in Treasury, 5,802,556 shares at December 31, 2004 and 8,819,600 shares at December 31, 2003	(200,695)	(299,582)
Total Shareholders' Equity	2,945,424	2,223,381
Total Liabilities and Shareholders' Equity	$ 5,798,923	$ 4,749,015

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(In Thousands, Except Per Share Amounts)	Preferred Stock	Common Stock	Additional Paid In Capital	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Shareholders' Equity
Balance at December 31, 2001	$ 147,582	$ 201,247	$ -	$ (14,953)	$ (55,118)	$1,668,708	$ (304,780)	$1,642,686
Net Income	-	-	-	-	-	87,173	-	87,173
Amortization of Preferred Stock Discount	417	-	-	-	-	(417)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,615)	-	(10,615)
Common Stock Dividends Declared, $0.16 Per Share	-	-	-	-	-	(18,499)	-	(18,499)
Translation Adjustment	-	-	-	-	4,315	-	-	4,315
Available-for-Sale Security Transactions	-	-	-	-	926	-	-	926
Treasury Stock Purchased	-	-	-	-	-	-	(63,139)	(63,139)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(9,457)	-	-	(2,402)	28,666	16,807
Employee Stock Purchase Plan	-	-	(39)	-	-	-	2,301	2,262
Tax Benefits from Stock Options Exercised	-	-	5,167	-	-	-	-	5,167
Restricted Stock and Units	-	-	4,329	(4,951)	-	-	622	-
Amortization of Unearned Compensation	-	-	-	4,871	-	-	-	4,871
Treasury Shares Issued as Compensation	-	-	-	-	-	-	441	441
Balance at December 31, 2002	147,999	201,247	-	(15,033)	(49,877)	1,723,948	(335,889)	1,672,395
Net Income	-	-	-	-	-	430,145	-	430,145
Amortization of Preferred Stock Discount	417	-	-	-	-	(417)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,615)	-	(10,615)
Common Stock Dividends Declared, $0.19 Per Share	-	-	-	-	-	(21,847)	-	(21,847)
Translation Adjustment	-	-	-	-	123,811	-	-	123,811
Treasury Stock Purchased	-	-	-	-	-	-	(25,208)	(25,208)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(16,522)	-	-	-	50,292	33,770
Employee Stock Purchase Plan	-	-	84	-	-	-	2,515	2,599
Tax Benefits from Stock Options Exercised	-	-	11,926	-	-	-	-	11,926
Restricted Stock and Units	-	-	6,084	(14,467)	-	-	8,383	-
Amortization of Unearned Compensation	-	-	-	6,027	-	-	-	6,027
Treasury Stock Issued as Compensation	-	-	53	-	-	-	325	378
Balance at December 31, 2003	148,416	201,247	1,625	(23,473)	73,934	2,121,214	(299,582)	2,223,381
Net Income	-	-	-	-	-	624,855	-	624,855
Redemption of Preferred Stock, $100,000 Per Share	(50,000)	-	-	-	-	-	-	(50,000)
Amortization of Preferred Stock Discount	410	-	-	-	-	(410)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,482)	-	(10,482)
Common Stock Dividends Declared, $0.24 Per Share	-	-	-	-	-	(28,332)	-	(28,332)
Translation Adjustment	-	-	-	-	77,925	-	-	77,925
Treasury Stock Purchased	-	-	-	-	-	-	(9,565)	(9,565)
Foreign Currency Swap Transaction Net of Income Tax Benefit of $1,972	-	-	-	-	(3,844)	-	-	(3,844)
Treasury Stock Issued Under:								
Stock Option Plans	-	-	(21,570)	-	-	-	101,077	79,507
Employee Stock Purchase Plan	-	-	694	-	-	-	2,326	3,020
Tax Benefits from Stock Options Exercised	-	-	29,396	-	-	-	-	29,396
Restricted Stock and Units	-	-	10,902	(15,951)	-	-	5,049	-
Amortization of Unearned Compensation	-	-	-	9,563	-	-	-	9,563
Balance at December 31, 2004	**$ 98,826**	**$ 201,247**	**$ 21,047**	**$ (29,861)**	**$ 148,015**	**$2,706,845**	**$ (200,695)**	**$2,945,424**

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)	Year Ended December 31 2004	2003	2002
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	**$ 624,855**	$ 430,145	$ 87,173
Items Not Requiring Cash			
Depreciation, Depletion and Amortization	**504,403**	441,843	398,036
Impairments	**81,530**	89,133	68,430
Deferred Income Taxes	**204,231**	191,726	82,179
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	**-**	7,131	-
Other, Net	**4,580**	1,033	17,333
Dry Hole Costs	**92,142**	41,156	46,749
Mark-to-Market Commodity Derivative Contracts			
Total Losses	**33,449**	80,414	48,508
Realized Losses	**(82,644)**	(44,870)	(21,136)
Collar Premium	**(520)**	(3,003)	(1,825)
Tax Benefits from Stock Options Exercised	**29,396**	11,926	5,168
Other, Net	**537**	2,141	(1,978)
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	**(151,799)**	(27,945)	(59,957)
Inventories	**(17,898)**	(2,840)	(57)
Accounts Payable	**136,716**	74,645	(21,468)
Accrued Taxes Payable	**18,197**	12,056	(85,208)
Other Liabilities	**(1,764)**	(3,257)	7,816
Other, Net	**(2,683)**	(15,314)	(1,199)
Changes in Components of Working Capital Associated with Investing and Financing Activities	**(28,381)**	(36,944)	43,093
Net Cash Provided by Operating Activities	**1,444,347**	1,249,176	611,657
Investing Cash Flows			
Additions to Oil and Gas Properties	**(1,416,684)**	(1,245,539)	(760,876)
Proceeds from Sales of Assets	**13,459**	13,553	7,514
Changes in Components of Working Capital Associated with Investing Activities	**26,788**	38,491	(43,557)
Other, Net	**(20,471)**	(13,946)	(19,213)
Net Cash Used in Investing Activities	**(1,396,908)**	(1,207,441)	(816,132)
Financing Cash Flows			
Net Commercial Paper and Line of Credit Borrowings (Repayments)	**(6,250)**	(36,260)	39,163
Long-Term Debt Borrowings	**150,000**	-	250,000
Long-Term Debt Repayments	**(175,000)**	-	-
Dividends Paid	**(37,595)**	(31,294)	(29,152)
Redemption of Preferred Stock	**(50,000)**	-	-
Treasury Stock Purchased	**-**	(21,295)	(63,038)
Proceeds from Stock Options Exercised	**75,510**	35,138	17,339
Other, Net	**97**	(3,485)	(3,008)
Net Cash Provided by (Used in) Financing Activities	**(43,238)**	(57,196)	211,304
Effect of Exchange Rate Changes on Cash	**12,336**	10,056	507
Increase (Decrease) in Cash and Cash Equivalents	**16,537**	(5,405)	7,336
Cash and Cash Equivalents at Beginning of Year	**4,443**	9,848	2,512
Cash and Cash Equivalents at End of Year	**$ 20,980**	$ 4,443	$ 9,848

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements of EOG Resources, Inc. (EOG) include the accounts of all domestic and foreign subsidiaries. Investments in unconsolidated affiliates, in which EOG is able to exercise significant influence, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Certain reclassifications have been made to prior period financial statements to conform with the current presentation.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable, accounts payable and long-term debt. The carrying values of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable and accounts payable approximate fair value (see Note 2 for fair value of long-term debt).

Cash and Cash Equivalents. EOG records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Oil and Gas Operations. EOG accounts for its natural gas and crude oil exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. Exploratory drilling costs are capitalized when drilling is complete if it is determined that there is economic producibility supported by either actual production, a conclusive formation test or by certain technical data if the discovery is located offshore in the Gulf of Mexico. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found due to the requirement of a significant capital investment. Such exploratory drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify development when the investment is made and additional exploratory wells are either in progress or firmly planned. All other exploratory wells that do not meet these criteria are expensed after one year. As of December 31, 2004 and 2003, EOG had exploratory drilling costs of $4.3 million and $4.5 million, respectively, related to an outside operated, deepwater offshore Gulf of Mexico discovery that has been deferred for more than one year and will require significant future capital expenditures before production can commence. These costs meet the accounting requirements outlined above for continued capitalization. As of December 31, 2004 and 2003, there were no material exploratory drilling costs capitalized for more than one year for projects that did not require a major capital investment. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of natural gas and crude oil, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets are depreciated on a straight-line basis.

Assets are grouped in accordance with paragraph 30 of Statement of Financial Accounting Standards (SFAS) No. 19. The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions, and 4) impairments.

EOG accounts for impairments under the provisions of SFAS No. 144 - "Accounting for the Impairment or Disposal of Long-Lived Assets." When circumstances indicate that an asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

Inventories, consisting primarily of tubular goods and well equipment held for use in the exploration for and development and production of natural gas and crude oil reserves, are carried at cost with adjustments made from time to time to recognize any reductions in value.

Arrangements for natural gas, crude oil, condensate and natural gas liquids sales are evidenced by signed contracts with determinable market prices and are recorded when production is delivered. A significant majority of the purchasers of these products have investment grade credit ratings and material credit losses have been rare. Revenues are recorded on the entitlement method based on EOG's percentage ownership of current production. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold on that owner's behalf may differ from that owner's ownership percentage. Under entitlement accounting, a receivable is recorded when underproduction occurs and a payable is recorded when overproduction occurs.

Capitalized Interest Costs. Interest capitalization is required for those properties if its effect, compared with the effect of expensing interest, is material. Accordingly, certain interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. The amount capitalized is an allocation of the interest cost incurred during the reporting period. Capitalized interest is computed only during the exploration and development activities and not on proved properties. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings.

Accounting for Price Risk Management Activities. EOG accounts for its price risk management activities under the provisions of SFAS No. 133 - "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. The statement establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. During the three year period ending December 31, 2004, EOG elected not to designate any of its price risk management activities as accounting hedges under SFAS No. 133, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change. The gains or losses are recorded in Gains (Losses) on Mark-to-Market Commodity Derivative Contracts. The related cash flow impact is reflected as cash flows from operating activities (see Note 11).

Income Taxes. EOG accounts for income taxes under the provisions of SFAS No. 109 - "Accounting for Income Taxes." SFAS No. 109 requires the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases (see Note 5).

Foreign Currency Translation. For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at year-end exchange rates and revenue and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Income (Loss). Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period.

Net Income Per Share. In accordance with the provisions of SFAS No. 128 - "Earnings per Share," basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted net income per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities (see Note 8 for additional information to reconcile the difference between the Average Number of Common Shares outstanding for basic and diluted net income per share).

Stock Options. EOG accounts for stock options under the provisions and related interpretations of Accounting Principles Board (APB) Opinion No. 25 - "Accounting for Stock Issued to Employees." No compensation expense is recognized for such options. As allowed by SFAS No. 123 - "Accounting for Stock-Based Compensation" issued in 1995, EOG has continued to apply APB Opinion No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123.

EOG's pro forma net income and net income per share of common stock for 2004, 2003 and 2002, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	2004	2003	2002
Net Income Available to Common - As Reported	**$ 614.0**	$ 419.1	$ 76.1
Deduct: Total Stock-Based Employee Compensation Expense, Net of Income Tax	**(11.9)**	(13.9)	(13.7)
Net Income Available to Common - Pro Forma	**$ 602.1**	$ 405.2	$ 62.4
Net Income Per Share Available to Common			
Basic - As Reported	**$ 5.25**	$ 3.66	$ 0.66
Basic - Pro Forma	**$ 5.15**	$ 3.54	$ 0.54
Diluted - As Reported	**$ 5.15**	$ 3.60	$ 0.65
Diluted - Pro Forma	**$ 5.05**	$ 3.48	$ 0.53

For grants made prior to August 2004, the fair value of each option grant is estimated using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in 2004, 2003 and 2002, respectively: (1) dividend yield of 0.4%, 0.4% and 0.4%, (2) expected volatility of 35%, 43% and 45%, (3) risk-free interest rate of 2.5%, 3.4% and 3.7%, and (4) expected life of 2.8 years, 5.2 years and 5.3 years.

Beginning in August 2004, EOG's stock options contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days (Capped Option). The fair value of each Capped Option grant is estimated using a Monte Carlo Simulation Model assuming a dividend yield of 0.4%, expected volatility of 31%, risk-free interest rate of 4.24% and a weighted-average expected life of 4.83 years. During 2004, approximately 1,377,000 stock options were granted at a weighted-average fair value of $21.06 and were included in the above pro forma employee stock based compensation expense calculation. Approximately 200,000 of the stock options were granted before August 2004 with an average fair value of $16.04, based on the Black-Scholes Option-Pricing Model. Approximately 1,177,000 of the stock options were granted with the Capped Option feature since August 1, 2004, with an average fair value of $21.91, based on the Monte Carlo Simulation Model. The average fair values for the stock options granted during 2003 and 2002 were $16.55 and $14.79, respectively.

The effects of applying SFAS No. 123 in this pro forma disclosure should not be interpreted as being indicative of future effects. SFAS No. 123 does not apply to awards prior to 1995, and the extent and timing of additional future awards cannot be predicted.

New Accounting Pronouncements. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 - "Accounting for Asset Retirement Obligations" effective for fiscal years beginning after June 15, 2002. SFAS No. 143 essentially requires entities to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. EOG adopted the statement on January 1, 2003. The impact of adopting the statement results in an after-tax charge of $7.1 million, which was reported in the first quarter of 2003 as cumulative effect of change in accounting principle.

During the third quarter of 2003, the SEC made comments to other registrants that oil and gas mineral rights acquired should be classified as an intangible asset pursuant to SFAS No. 141 – "Business Combinations," and SFAS No. 142 – "Goodwill and Other Intangible Assets." On September 2, 2004, FASB Staff Position 142-2, "Application of FASB Statement No. 142, "Goodwill and Other Intangible Assets," to Oil- and Gas-Producing Entities" was issued. The FASB staff believes that the scope exception in paragraph 8(b) of Statement 142 extends to its disclosure provisions for drilling and mineral rights of oil- and gas-producing entities. Accordingly, the SEC comments made to the other registrants have no impact on EOG's financial statements.

On April 1, 2004, EOG adopted prospectively FASB Staff Position No. 106-2 – "Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), which provides guidance on accounting for the effects of the Medicare Prescription Drug Improvement Act of 2003 for employers that sponsor postretirement health care plans that provide prescription drug benefits. The adoption of FSP 106-2 did not have a material impact on EOG's financial statements (see Note 6 for further information on EOG's postretirement plan).

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010. The Act also provides for a two-year phase out of the existing extra-territorial income exclusion (ETI) for foreign sales that was viewed to be inconsistent with international trade protocols by the European Union. EOG expects the net effect of the phase out of the ETI and the phase in of this new deduction to result in favorable adjustments to the effective tax rate for 2005 and subsequent years. Under the guidance in FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004," the deduction will be treated as a "special deduction" as described in FASB 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the period in which the deduction is claimed on EOG's tax return.

The Act also creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, currently, uncertainty remains as to how to interpret some provisions in the Act. The Act limits the qualified dividends to the greater of $500 million or the amount of earnings permanently reinvested outside the United States, as reported in the 2002 financial statements, which was $550 million. In addition, a comprehensive analysis of foreign legal and tax ramifications must be completed before such dividends are declared. As such, EOG is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the United States. EOG expects to be in a position to complete the assessment by September 30, 2005.

In December 2002, the FASB issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which supersedes SFAS No. 148. SFAS No. 123(R) establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25. SFAS No. 123(R) will be effective for interim or annual reporting periods beginning on or after June 15, 2005. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 using the modified prospective method. EOG expects that the adoption of SFAS No. 123(R) would reduce second half 2005 net earnings by a pre-tax amount of approximately $10 million, taking into consideration the estimated forfeitures and cancellations. The amount includes approximately $0.5 million for the Employee Stock Purchase Plan. SFAS No. 123(R) also requires a public entity to present its cash flows provided by tax benefits from stock options exercised in the Financing Cash Flows section of the Statement of Cash Flows. Had SFAS No. 123(R) been in effect, EOG's Net Cash Provided by Operating Activities would have been reduced and its Net Cash Provided by Financing Activities would have been increased on its Consolidated Statements of Cash Flows by $29 million, $12 million and $5 million for 2004, 2003 and 2002, respectively (see Note 6 for further information on EOG's stock-based compensation plans).

2. LONG-TERM DEBT

Long-Term Debt at December 31 of the years indicated consisted of the following (in thousands):

	2004	2003
Commercial Paper	**$ 91,800**	$ 98,050
Senior Unsecured Term		
Loan Facility due 2005	**75,000**	150,000
6.50% Notes due 2004	**-**	100,000
6.70% Notes due 2006	**126,870**	126,870
6.50% Notes due 2007	**100,000**	100,000
6.00% Notes due 2008	**173,952**	173,952
6.65% Notes due 2028	**140,000**	140,000
7.00% Subsidiary Debt due 2011	**220,000**	220,000
4.75% Subsidiary Debt due 2014	**150,000**	-
Total	**$ 1,077,622**	$ 1,108,872

During 2004, EOG utilized commercial paper and during 2003, EOG utilized commercial paper and short-term funding from uncommitted credit facilities, both bearing market interest rates, for various corporate financing purposes. Commercial paper and uncommitted credit borrowings are classified as long-term debt based on EOG's intent and ability to ultimately replace such amounts with other long-term debt.

On July 23, 2003, EOG entered into a new three-year Revolving Credit Agreement (Agreement) with domestic and foreign lenders which provides for $600 million in long-term committed credit, and concurrently cancelled the existing $300 million 364-day credit facility and $300 million five-year credit facility scheduled to expire in July 2003 and July 2004, respectively. This Agreement provides EOG the ability to replace the commercial paper, uncommitted credit borrowing and any maturity of debt. Advances under the Agreement bear interest based upon a base rate or a Eurodollar rate at the option of EOG. The Agreement also provides for the allocation, at the option of EOG, of up to $75 million of the $600 million to its Canadian subsidiary. Advances to the Canadian subsidiary, should they occur, would be guaranteed by EOG and would bear interest at the option of the Canadian subsidiary based upon a Canadian prime rate or a Canadian banker's acceptance rate. EOG also has the option to issue up to $100 million in letters of credit as part of this Agreement. No amounts were borrowed under this Agreement at December 31, 2004. The applicable base rates for this Facility, had there been any amounts borrowed under this Agreement would have been 5.25% and 4.00% at December 31, 2004 and December 31, 2003, respectively. The applicable Eurodollar rates for this Facility, had there been any amounts borrowed under this Agreement would have been 2.90% and 1.62% at December 31, 2004 and December 31, 2003, respectively.

EOG maintains a three-year Senior Unsecured Term Loan Facility (Facility) with a group of banks whereby the banks lent EOG $150 million with a maturity date of October 30, 2005. This Facility calls for interest to be charged at a spread over LIBOR (London InterBank Offering Rate) or the base rate at EOG's option, and contains substantially the same covenants as those in EOG's $600 million Long-Term Revolving Credit Agreement. On March 31, 2004, EOG repaid $75 million of the $150 million loan. The remaining $75 million balance is classified as long-term debt based on EOG's intent and ability to ultimately replace such amounts with other long-term debt. The applicable interest rates for the Facility were 3.17% and 1.88% at December 31, 2004 and December 31, 2003, respectively.

On March 9, 2004, under Rule 144A of the Securities Act of 1933, as amended, EOG Resources Canada Inc., a wholly owned subsidiary of EOG, issued notes with a total principal amount of US$150 million, an annual interest rate of 4.75% and a maturity date of March 15, 2014. The notes are guaranteed by EOG. In conjunction with the offering, EOG entered into a foreign currency swap transaction with multiple banks for the equivalent amount of the notes and related interest, which has in effect converted this indebtedness into CAD$201.3 million with a 5.275% interest rate.

The 6.00% to 6.70% Notes due 2006 to 2028 were issued through public offerings and have effective interest rates of 6.16% to 6.81%. The Subsidiary Debt due 2011 bears interest at a fixed rate of 7.00% and is guaranteed by EOG. The weighted average interest rate for the commercial paper was 1.45% for 2004.

On September 15, 2004, EOG repaid in full upon maturity the $100 million, 6.50% Notes.

At December 31, 2004, the aggregate annual maturities of long-term debt were $75 million for 2005, $127 million in 2006, $100 million for 2007, $174 million for 2008 and zero for 2009.

Both EOG's Credit Agreement and Facility contain certain restrictive covenants, including a maximum debt-to-total capitalization ratio of 65% and a minimum ratio of EBITDAX (earnings before interest, taxes, DD&A, and exploration expense) to interest expense of at least three times. Other than these covenants, EOG does not have any other financial covenants in its financing agreements. EOG continues to comply with these two covenants and does not view them as materially restrictive.

Shelf Registration. As of February 25, 2005, the amount available under various filed registration statements with the SEC for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock totaled $688 million.

Fair Value Of Long-Term Debt. At December 31, 2004 and 2003, EOG had $1,078 million and $1,109 million, respectively, of long-term debt, which had fair values of approximately $1,146 million and $1,175 million, respectively. The fair value of long-term debt is the value EOG would have to pay to retire the debt, including any premium or discount to the debt-holder for the differential between the stated interest rate and the year-end market rate. The fair value of long-term debt is based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at year-end.

3. SHAREHOLDERS' EQUITY

Common Stock. EOG purchases its common stock from time to time in the open market to be held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock plans and any other approved transactions or activities for which such common stock shall be required. In September 2001, the Board of Directors authorized the purchase of an aggregate maximum of 10 million shares of common stock of EOG which superseded all previous authorizations. At December 31, 2004, 6,386,200 shares remain available for repurchases under this authorization. On February 2, 2005, EOG announced that the Board of Directors had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and to be issued on March 1, 2005. In addition, the Board increased the quarterly cash dividend on the common stock by 33%, resulting in a quarterly cash dividend of $0.08 per share pre-split or $0.04 per share post-split.

The following summarizes shares of common stock outstanding at December 31, for each of the years ended December 31 (in thousands):

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2001	124,730	(9,278)	115,452
Treasury Stock Purchased	-	(1,703)	(1,703)
Treasury Stock Issued Under Stock Option Plans	-	870	870
Treasury Stock Issued Under Employee Stock Purchase Plan	-	69	69
Restricted Stock and Units	-	19	19
Treasury Stock Issued as Compensation	-	13	13
Balance at December 31, 2002	124,730	(10,010)	114,720
Treasury Stock Purchased	-	(626)	(626)
Treasury Stock Issued under Stock Option Plans	-	1,485	1,485
Treasury Stock Issued Under Employee Stock Purchase Plan	-	74	74
Restricted Stock and Units	-	247	247
Treasury Stock Issued as Compensation	-	10	10
Balance at December 31, 2003	124,730	(8,820)	115,910
Treasury Stock Purchased	-	(160)	(160)
Treasury Stock Issued Under Stock Option Plans	-	2,961	2,961
Treasury Stock Issued Under Employee Stock Purchase Plan	-	68	68
Restricted Stock and Units	-	148	148
Balance at December 31, 2004	**124,730**	**(5,803)**	**118,927**

On February 14, 2000, EOG's Board of Directors declared a dividend of one preferred share purchase right (a "Right," and the agreement governing the terms of such Rights, the "Rights Agreement") for each outstanding share of common stock, par value $0.01 per share. The Board of Directors has adopted this Rights Agreement to protect stockholders from coercive or otherwise unfair takeover tactics. The dividend was distributed to the stockholders of record on February 24, 2000. As mentioned above, on March 1, 2005, EOG will effect a two-for-one stock split in the form of a stock dividend. In accordance with the Rights Agreement, each share of common stock issued in connection with the stock split will have one Right associated with it. Each Right, expiring February 24, 2010, represents a right to buy from EOG one hundredth (1/100) of a share of Series E Junior Participating Preferred Stock (Preferred Share) for $90, once the Rights become exercisable. This portion of a Preferred Share will give the stockholder approximately the same dividend, voting, and liquidation rights as would one share of common stock. Prior to exercise, the Right does not give its holder any dividend, voting, or liquidation rights. If issued, each one hundredth (1/100) of a Preferred Share: (i) will not be redeemable; (ii) will entitle holders to quarterly dividend payments of $0.01 per share, or an amount equal to the dividend paid on one share of common stock, whichever is greater; (iii) will entitle holders upon liquidation either to receive $1 per share or an amount equal to the payment made on one share of common stock, whichever is greater; (iv) will have the same voting power as one share of common stock; and (v) if shares of EOG's common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock.

The Rights will not be exercisable until ten days after the public announcement that a person or group has become an acquiring person (Acquiring Person) by obtaining beneficial ownership of 10% or more of EOG's common stock, or if earlier, ten business days (or a later date determined by EOG's Board of Directors before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if consummated, would result in that person or group becoming an Acquiring Person. On February 24, 2005, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 20% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the following requirements: (i) the institutional investor is described in Rule 13d-1(b)(1) promulgated under the Securities Exchange Act of 1934 and is eligible to report (and, if such institutional investor is the beneficial owner of greater than

5% of EOG's common stock, does in fact report) beneficial ownership of common stock on Schedule 13G; (ii) the institutional investor is not required to file a Schedule 13D (or any successor or comparable report) with respect to its beneficial ownership of EOG's common stock; (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates other than those which, under published interpretations of the United States Securities and Exchange Commission or its staff, are eligible to file separate reports on Schedule 13G with respect to their beneficial ownership of EOG's common stock); and (iv) the institutional investor does not beneficially own 20% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates).

If a person or group becomes an Acquiring Person, all holders of Rights, except the Acquiring Person, may for $90, purchase shares of EOG's common stock with a market value of $180, based on the market price of the common stock prior to such acquisition. If EOG is later acquired in a merger or similar transaction after the Rights become exercisable, all holders of Rights except the Acquiring Person may, for $90, purchase shares of the acquiring corporation with a market value of $180 based on the market price of the acquiring corporation's stock, prior to such merger.

EOG's Board of Directors may redeem the Rights for $0.01 per Right at any time before any person or group becomes an Acquiring Person. If the Board of Directors redeems any Rights, it must redeem all of the Rights. Once the Rights are redeemed, the only right of the holders of Rights will be to receive the redemption price of $0.01 per Right. The redemption price will be adjusted if EOG has a stock split or stock dividends of EOG's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of EOG's outstanding common stock, the Board of Directors may exchange the Rights for common stock or equivalent security at an exchange ratio of one share of common stock or an equivalent security for each such Right, other than Rights held by the Acquiring Person.

Preferred Stock. EOG currently has two authorized series of preferred stock. On February 14, 2000, EOG's Board of Directors, in connection with the Rights Agreement described above, authorized 1,500,000 shares of Series E Junior Participating Preferred Stock with the rights and preferences described above. On February 24, 2005, EOG's Board of Directors increased the authorized shares of Series E Junior Participating Preferred Stock to 3,000,000 as a result of the two-for-one stock split mentioned above. Currently, there are no shares of the Series E Junior Participating Preferred Stock outstanding.

On July 19, 2000, EOG's Board of Directors authorized 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (the "Series B"). Dividends are payable on the shares only if declared by EOG's Board of Directors and will be cumulative. If declared, dividends will be payable at a rate of $71.95 per share, per year on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. EOG may redeem all or part of the Series B at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The Series B is not convertible into, or exchangeable for, common stock of EOG. There are 100,000 shares of the Series B currently outstanding.

On July 25, 2000, EOG's Board of Directors authorized 500 shares of Flexible Money Market Cumulative Preferred Stock, Series D, with a liquidation preference of $100,000 per share (the "Series D"). Dividends were payable on the shares only if declared by EOG's Board of Directors and were cumulative. The initial dividend rate on the shares was 6.84% until December 15, 2004. Through December 15, 2004, dividends were payable, if declared, on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. On December 15, 2004, EOG redeemed all 500 outstanding shares of the Series D at a redemption price of $100,000 per share plus accumulated and unpaid dividends for a total of $50 million. On February 24, 2005, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware to eliminate the Series D from EOG's Restated Certificate of Incorporation, as amended.

4. OTHER INCOME (EXPENSE), NET

Other Income (Expense), Net for 2004 included income from equity investments of $11 million, gains on sales of reserves and related assets of $6 million and foreign currency transaction losses of $7 million. Other Income (Expense), Net for 2003 included foreign currency transaction gains of $9 million and income from equity investments of $4 million. The foreign currency transaction gain and loss amounts for 2004 and 2003 are results of applying the changes in the Canadian exchange rate to certain intercompany short-term loans that eliminate in consolidation.

5. INCOME TAXES

The principal components of EOG's net deferred income tax liability at December 31 were as follows (in thousands):

	2004	2003
Current Deferred Income Tax Assets		
Commodity Hedging Contracts	$ (7,701)	$ 9,739
Deferred Compensation Plans	6,488	4,994
Net Operating Loss Carryforward	-	5,225
United Kingdom Net Operating Loss Carryforward (Current Portion)	10,160	-
Other	13,280	11,590
Total Current Deferred Income Tax Assets	22,227	31,548
Current Deferred Income Tax Liabilities		
Timing Differences Associated With Different Year-Ends in Foreign Jurisdictions	103,903	73,611
Other	30	-
Total Current Deferred Income Tax Liabilities	103,933	73,611
Total Net Current Deferred Income Tax Liabilities	$ 81,706	$ 42,063
Noncurrent Deferred Income Tax Assets (included in Other Assets)		
United Kingdom Net Operating Loss Carryforward	$ 21,764	$ 3,688
United Kingdom Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	(20,465)	-
Total Noncurrent Deferred Income Tax Assets	$ 1,299	$ 3,688
Noncurrent Deferred Income Tax Assets		
Non-Producing Leasehold Costs	$ 41,718	$ 36,154
Seismic Costs Capitalized for Tax	25,563	21,365
Alternative Minimum Tax Credit Carryforward	-	3,869
Other	22,740	20,124
Total Noncurrent Deferred Income Tax Assets	90,021	81,512
Noncurrent Deferred Income Tax Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	974,492	837,189
Capitalized Interest	16,683	13,451
Other	1,200	-
Total Noncurrent Deferred Income Tax Liabilities	992,375	850,640
Total Net Noncurrent Deferred Income Tax Liability	$ 902,354	$ 769,128
Total Net Deferred Income Tax Liability	$ 982,761	$ 807,503

The components of income before income taxes were as follows (in thousands):

	2004	2003	2002
United States	$ 641,973	$442,109	$ 37,354
Foreign	284,039	211,767	82,318
Total	$ 926,012	$653,876	$ 119,672

The principal components of EOG's income tax provision for the years indicated below were as follows (in thousands):

	2004	2003	2002
Current:			
Federal	$ 58,148	$ 3,844	$ (61,013)
State	3,137	880	(5,130)
Foreign	35,641	20,150	16,463
Total	96,926	24,874	(49,680)
Deferred:			
Federal	156,862	151,389	57,232
State	7,985	4,052	(358)
Foreign	39,384	36,285	25,305
Total	204,231	191,726	82,179
Income Tax Provision	$ 301,157	$ 216,600	$ 32,499

The differences between taxes computed at the United States federal statutory tax rate and EOG's effective rate were as follows:

	2004	2003	2002
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	0.74	0.73	0.22
Income Tax Provision Related to Foreign Operations	(1.83)	(0.05)	(3.54)
Change in Canadian Federal Tax Rate	-	(2.16)	-
Change in Canadian Provincial Tax Rate	(0.58)	-	-
Tight Gas Sands Federal Income Tax Credits	-	-	(3.57)
Other	(0.81)	(0.40)	(0.95)
Effective Income Tax Rate	32.52%	33.12%	27.16%

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. The Act creates a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, currently, uncertainty remains as to how to interpret some provisions in the Act. The Act limits the qualified dividends to the greater of $500 million or the amount of earnings permanently reinvested outside the United States, as reported in the 2002 financial statements, which was $550 million. In addition, a comprehensive analysis of foreign legal and tax ramifications must be completed before such dividends are declared. As such, EOG is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the United States. EOG expects to be in a position to complete the assessment by September 30, 2005.

EOG's foreign subsidiaries' undistributed earnings of approximately $1 billion at December 31, 2004 are considered to be indefinitely invested outside the United States and, accordingly, no United States or state income taxes have been provided thereon. Upon distribution of those earnings in the form of dividends, EOG may be subject to both foreign withholding taxes and United States income taxes, net of allowable foreign tax credits. Determination of any potential amount of unrecognized deferred income tax liabilities is not practicable.

EOG incurred a tax net operating loss of $191 million in 2002. During 2003, EOG utilized $176 million of the 2002 net operating loss. The remaining net operating loss of $15 million was utilized in 2004.

A foreign net operating loss of $80 million, of which $55 million was incurred during 2004, will be carried forward indefinitely until utilized.

EOG had an alternative minimum tax (AMT) credit carry forward from prior years of $6 million which was used to offset regular income taxes in 2004.

6. EMPLOYEE BENEFIT PLANS

Pension Plans

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. EOG's contributions to these pension plans are based on various percentages of compensation, and in some instances, are based upon the amount of the employees' contributions. For 2004, 2003 and 2002, EOG's total contributions to these pension plans amounted to $10.6 million, $8.2 million and $8.0 million, respectively.

In addition, EOG's Canadian subsidiary maintains a non-contributory defined contribution pension plan and a matched defined contribution savings plan and EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. These pension plans are available to most employees of the Canadian and Trinidadian subsidiaries and EOG's combined contributions to these pension plans were approximately $860,000, $630,000 and $460,000 for 2004, 2003 and 2002, respectively.

EOG's United Kingdom subsidiary introduced a pension plan as of January 2005. The United Kingdom subsidiary will include a defined non-contributory pension plan and a matched defined contribution savings plan. The pension plan will be available to all employees of the United Kingdom subsidiary.

Postretirement Plan

EOG has postretirement medical and dental benefits in place for eligible employees and their eligible dependents. Benefits are provided under the provisions of a contributory defined dollar benefit plan. EOG accrues these postretirement benefit costs over the service lives of the employees expected to be eligible to receive such benefits. The following table summarizes EOG's postretirement benefit plan as of December 31 of the years indicated as follows (in thousands):

	2004	2003	2002
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	$ 3,011	$ 1,875	$ 2,021
Service Cost	175	175	139
Interest Cost	136	131	115
Plan Participants' Contributions	73	64	58
Amendments	-	773	-
Benefits Paid	(136)	(102)	(95)
Actuarial (Gain) Loss	(1,276)	95	(363)
Benefit Obligation at Year-End	$ 1,983	$ 3,011	$ 1,875
Change in Plan Asset			
Fair Value of Plan Asset at Beginning of Year	$ -	$ -	$ -
Employer Contributions	63	38	37
Plan Participants' Contributions	73	64	58
Benefits Paid	(136)	(102)	(95)
Fair Value of Plan Asset at Year-End	$ -	$ -	$ -
Reconciliation of Funded Status to Balance Sheet			
Funded Status	$ 1,983	$ 3,011	$ 1,875
Unrecognized Net Actuarial Gain (Loss)	1,158	(64)	35
Unrecognized Prior Service Cost	(1,517)	(1,647)	(948)
Accrued Benefit Cost at Year-End	$ 1,624	$ 1,300	$ 962
Components of Net Periodic Benefit Cost			
Service Cost	$ 175	$ 175	$ 139
Interest Cost	136	131	115
Amortization of Prior Service Cost	129	75	75
Recognized Net Actuarial Gain	(53)	-	(1)
Net Periodic Benefit Cost	$ 387	$ 381	$ 328

Weighted-average discount rate assumptions used in the determination of benefit obligations at December 31, 2004, 2003 and 2002 were 5.95%, 6.15% and 6.40%, respectively. Weighted-average discount rate assumptions used in the determination of net periodic benefit cost for years ended December 31, 2004, 2003 and 2002 were 6.15%, 6.40% and 7.00%, respectively.

Estimated Future Employer-Paid Benefits. The following benefits, which reflect expected future service, as appropriate, are expected to be paid by EOG in the next 10 years (in thousands):

	Postretirement Employer-Paid Benefits
2005	$ 84
2006	91
2007	96
2008	103
2009	126
2010 - 2014	924

Postretirement health care trend rates have zero effect on the amounts reported for the postretirement health care plan for both 2004 and 2003. A one-percentage point increase or decrease in EOG's healthcare cost trend rates would have zero impact on the postretirement benefit obligation, as any increase or decrease in healthcare costs would be borne by the employee.

Stock Plans

EOG has various stock plans (Plans) under which employees and non-employee members of the Board of Directors of EOG and its subsidiaries have been or may be granted certain equity compensation. Since the inception of the Plans, there have been 31,445,000 shares authorized for grant. At December 31, 2004, 3,708,827 shares remain available for grant.

Stock Options. Under the Plans, participants have been or may be granted rights to purchase shares of common stock of EOG at a price not less than the market price of the stock at the date of grant. Stock options granted under the Plans vest either immediately at the date of grant or up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options granted under the Plans have not exceeded a maximum term of 10 years.

Beginning in August 2004, EOG's stock options contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days.

The following table sets forth the option transactions for the years ended December 31 (options in thousands):

	2004		2003		2002	
	Options	Average Grant Price	Options	Average Grant Price	Options	Average Grant Price
Outstanding at January 1	**7,751**	**$ 30.38**	7,842	$ 27.31	7,013	$ 24.69
Granted	**1,307**	**63.94**	1,515	39.13	1,809	33.82
Exercised	**(2,961)**	**26.85**	(1,485)	22.73	(868)	19.90
Forfeited	**(140)**	**38.57**	(121)	34.74	(112)	27.64
Outstanding at December 31	**5,957**	**39.32**	7,751	30.38	7,842	27.31
Options Exercisable at December 31	**3,050**	**30.37**	4,933	27.03	5,041	23.96
Available for Future Grant	**3,709**		1,178		2,932	

EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 (see Note 1) and as a result, EOG expects the expensing of the stock options would reduce second half 2005 net earnings by a pre-tax amount of approximately $9.5 million.

The following table summarizes certain information for the options outstanding at December 31, 2004 (options in thousands):

	Options Outstanding			Options Exercisable	
Range of Grant Prices	Options	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Options	Weighted Average Grant Price
$14.00 to $17.99	362	4	$ 14.53	362	$ 14.53
18.00 to 22.99	512	4	20.05	512	20.05
23.00 to 28.99	44	3	24.97	42	24.85
29.00 to 33.99	1,627	7	33.32	1,067	33.14
34.00 to 39.99	1,905	8	37.47	882	36.75
40.00 to 54.99	292	8	45.60	177	44.03
55.00 to 73.99	1,215	10	64.78	8	61.22
	5,957	7	39.32	**3,050**	30.37

During 2004, 2003 and 2002, EOG repurchased approximately 160,000, 626,000 and 1,703,000 of its common shares, respectively. The difference between the cost of the treasury shares and the exercise price of the options, net of federal income tax benefit of $29.4 million, $11.9 million and $5.2 million, for the years 2004, 2003 and 2002, respectively, is reflected as an adjustment to additional paid in capital to the extent EOG has accumulated additional paid in capital relating to treasury stock and to retained earnings thereafter.

Restricted Stock and Units. Under the Plans, employees may be granted restricted stock and/or units without cost to them. The shares and units granted vest to the employee at various times ranging from one to five years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Upon vesting, restricted shares are released to the employee. Upon vesting, restricted units are converted into one share of common stock and released to the employee. The following summarizes shares of restricted stock and units granted for the three years ended December 31 (shares and units in thousands):

	Restricted Shares and Units		
	2004	2003	2002
Outstanding at January 1	**1,026**	775	632
Granted	**330**	372	158
Released	**(41)**	(103)	(10)
Forfeited or Expired	**(32)**	(18)	(5)
Outstanding at December 31	**1,283**	1,026	775
Average Fair Value of Shares Granted During Year	**$ 51.43**	$ 40.43	$ 32.56

The fair value of the restricted shares and units at date of grant has been recorded in shareholders' equity as unearned compensation and is being amortized over the vesting period as compensation expense. Related compensation expense for 2004, 2003 and 2002 was $9.6 million, $6.0 million and $4.9 million, respectively.

Employee Stock Purchase Plan. EOG has an Employee Stock Purchase Plan (ESPP) in place that allows eligible employees to semi-annually purchase, through payroll deductions, shares of EOG common stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employees' pay (subject to certain ESPP limits) during each of the two six-month offering periods. As of December 31, 2004, approximately 256,600 common shares remained available for issuance under the plan. EOG currently expects to adopt SFAS No. 123(R) effective July 1, 2005 (see Note 1) and as a result, EOG expects the expense associated with the ESPP would reduce second half 2005 net earnings by a pre-tax amount of approximately $0.5 million.

The following table summarizes ESPP activities for the years ended December 31 (in thousands, except number of participants):

	2004	2003	2002
Approximate Number of Participants	**450**	410	350
Shares Purchased	**68**	74	69
Aggregate Purchase Price	**$ 3,021**	$ 2,599	$ 2,261

7. COMMITMENTS AND CONTINGENCIES

Letters Of Credit. At December 31, 2004 and 2003, EOG had standby letters of credit and guarantees outstanding totaling approximately $433 million and $266 million, respectively. Of these amounts, $370 million and $220 million, respectively, represent guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt" while $63 million and $46 million, respectively, primarily represent guarantees of payment obligations on behalf of subsidiaries. As of February 25, 2005, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2004, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase and other purchase obligations, and pipeline transportation service commitments, based on current transportation rates and the foreign currency exchange rates at December 31, 2004, are as follows (in thousands):

	Total Minimum Commitments
2005	$ 45,868
2006 - 2008	72,814
2009 - 2010	24,733
2011 and Beyond	44,388
	$187,803

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2015. Rental expenses associated with these leases amounted to $26 million, $22 million and $21 million for 2004, 2003 and 2002, respectively.

Contingencies. There are various suits and claims against EOG that have arisen in the ordinary course of business. Management believes that the chance that these suits and claims will individually or in the aggregate have a material adverse effect on the financial condition or results of operations of EOG is remote. When necessary, EOG has made accruals in accordance with SFAS No. 5 - "Accounting for Contingencies," in order to provide for these matters.

8. NET INCOME PER SHARE AVAILABLE TO COMMON

The following table sets forth the computation of Net Income Per Share Available to Common for the years ended December 31 (in thousands, except per share amounts):

	2004	2003	2002
Numerator for basic and diluted earnings per share -			
Net income available to common	$ 613,963	$ 419,113	$ 76,141
Denominator for basic earnings per share -			
Weighted average shares	116,876	114,597	115,335
Potential dilutive common shares -			
Stock options	1,780	1,584	1,633
Restricted stock and units	532	338	277
Denominator for diluted earnings per share -			
Adjusted weighted average shares	119,188	116,519	117,245
Net Income Per Share Available to Common			
Basic	$ 5.25	$ 3.66	$ 0.66
Diluted	$ 5.15	$ 3.60	$ 0.65

9. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes was as follows for the years ended December 31 (in thousands):

	2004	2003	2002
Interest	$ 60,967	$ 62,472	$ 54,432
Income taxes	56,654	26,330	15,946

10. BUSINESS SEGMENT INFORMATION

EOG's operations are all natural gas and crude oil exploration and production related. SFAS No. 131 - "Disclosures about Segments of an Enterprise and Related Information," establishes standards for reporting information about operating segments in annual financial statements and requires selected information about operating segments in interim financial reports. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker, or decision making group, in deciding how to allocate resources and in assessing performance. EOG's chief operating decision making process is informal and involves the Chairman and Chief Executive Officer and other key officers. This group routinely reviews and makes operating decisions related to significant issues associated with each of EOG's major producing areas in the United States and each significant international location. For segment reporting purposes, the major United States producing areas have been aggregated as one reportable segment due to similarities in their operations as allowed by SFAS No. 131.

Financial information by reportable segment is presented below for the years ended December 31, or at December 31 (in thousands):

	United States	Canada	Trinidad	United Kingdom	Other	Total
2004						
Net Operating Revenues	**$ 1,656,325[1]**	**$ 448,562[1]**	**$ 153,377**	**$ 12,961**	**$ -**	**$ 2,271,225[1]**
Depreciation, Depletion and Amortization	**382,718**	**99,879**	**20,022**	**1,784**	**-**	**504,403**
Operating Income (Loss)	**682,619**	**222,155**	**91,245**	**(16,824)**	**-**	**979,195**
Interest Income	**292**	**679**	**659**	**-**	**-**	**1,630**
Other Income (Expense)	**1,072**	**(4,487)**	**10,892**	**838**	**-**	**8,315**
Interest Expense, Net	**41,571**	**21,415**	**-**	**142**	**-**	**63,128**
Income (Loss) Before Income Taxes	**642,412**	**196,932**	**102,796**	**(16,128)**	**-**	**926,012**
Income Tax Provision (Benefit)	**231,250**	**45,785**	**31,414**	**(7,292)**	**-**	**301,157**
Additions to Oil and Gas Properties	**936,463**	**294,571**	**59,205**	**34,303**	**-**	**1,324,542**
Total Assets	**3,727,231**	**1,600,486**	**401,434**	**69,772**	**-**	**5,798,923**
2003						
Net Operating Revenues	$ 1,335,145[2]	$ 309,418[2]	$ 100,112	$ -	$ -	$ 1,744,675[2]
Depreciation, Depletion and Amortization	359,439	66,334	16,070	-	-	441,843
Operating Income (Loss)	487,133	163,783	55,433	(9,195)	160	697,314
Interest Income	1,385	950	454	-	-	2,789
Other Income (Expense)	2,777	6,354	3,418	(71)	6	12,484
Interest Expense, Net	43,421	14,618	670	-	2	58,711
Income (Loss) Before Income Taxes	447,874	156,469	58,635	(9,266)	164	653,876
Income Tax Provision (Benefit)	163,359	36,190	20,671	(3,486)	(134)	216,600
Additions to Oil and Gas Properties	605,667	552,164	31,942	14,610	-	1,204,383
Total Assets	3,119,474	1,302,753	309,727	17,061	-	4,749,015
2002						
Net Operating Revenues	$ 846,007[3]	$ 169,106[3]	$ 79,551	$ -	$ 18	$ 1,094,682[3]
Depreciation, Depletion and Amortization	334,318	49,622	14,085	-	11	398,036
Operating Income (Loss)	93,600	40,587	49,450	(250)	(2,410)	180,977
Interest Income	765	229	348	-	-	1,342
Other Income (Expense)	(3,652)	261	394	-	4	(2,993)
Interest Expense, Net	45,907	13,534	211	-	2	59,654
Income (Loss) Before Income Taxes	44,806	27,543	49,981	(250)	(2,408)	119,672
Income Tax Provision (Benefit)	(7,684)	20,359	20,974	300	(1,450)	32,499
Additions to Oil and Gas Properties	517,598	160,840	35,689	-	-	714,127
Total Assets	2,864,862	665,202	283,395	66	43	3,813,568

(1) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2004 that totaled $280 million of consolidated Net Operating Revenues.

(2) EOG had sales activity with two significant purchasers, one totaled $222 million and the other totaled $182 million, of consolidated Net Operating Revenues in the United States and Canada segments in 2003.

(3) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2002 that totaled $163 million of the consolidated Net Operating Revenues.

11. PRICE, INTEREST RATE AND CREDIT RISK MANAGEMENT ACTIVITIES

Price and Interest Rate Risks. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for natural gas and crude oil. EOG utilizes derivative financial instruments, primarily price swaps and collars, as the means to manage this price risk. In addition to these financial transactions, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. Under SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149, these various physical commodity contracts qualify for the normal purchases and normal sales exception and therefore, are not subject to hedge accounting or mark-to-market accounting. The financial impact of these various physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

During 2004, 2003 and 2002, EOG elected not to designate any of its derivative financial contracts as accounting hedges and accordingly, accounted for these derivative financial contracts using mark-to-market accounting. During 2004, EOG recognized losses on mark-to-market commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million. During 2003, EOG recognized losses on mark-to-market commodity derivative contracts of $80 million, which included realized losses of $45 million and collar premium payments of $3 million. During 2002, EOG recognized losses on mark-to-market commodity derivative contracts of $49 million, which included realized losses of $21 million and a $2 million collar premium payment.

Presented below is a summary of EOG's 2005 natural gas financial collar contracts at December 31, 2004. As indicated, EOG does not have any financial collar or swap contracts that cover periods beyond March 2005. Moreover, EOG has not entered into any additional natural gas financial collar contracts or natural gas or crude oil financial price swap contracts since December 31, 2004. EOG accounts for these collar contracts using mark-to-market accounting. The total fair value of the natural gas financial collar contracts at December 31, 2004 was $11 million.

	Natural Gas Financial Collar Contracts				
		Floor Price		Ceiling Price	
2005	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average ($/MMBtu)
Jan(1)	75,000	$7.65 - 8.00	$7.77	$8.90 - 9.50	$9.10
Feb(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32
Mar(2)	75,000	7.65 - 8.00	7.77	9.19 - 9.50	9.32

(1) Notional volumes of 25,000 MMBtud of the January 2005 collar contracts were purchased at a premium of $0.10 per MMBtu.

(2) The collar contracts for February 2005 and March 2005 were purchased at a premium of $0.10 per MMBtu.

The following table summarizes the estimated fair value of financial instruments and related transactions at December 31 of the years indicated as follows (in millions):

	2004		2003	
	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-Term Debt(2) . .	**$1,078**	**$1,146**	$1,109	$1,175
NYMEX-Related Commodity Market Positions	**11**	**11**	(38)	(38)

(1) Estimated fair values have been determined by using available market data and valuation methodologies. Judgment is required in interpreting market data and the use of different market assumptions or estimation methodologies may affect the estimated fair value amounts.

(2) See Note 2.

Credit Risk. While notional contract amounts are used to express the magnitude of commodity price and interest rate swap agreements, the amounts potentially subject to credit risk, in the event of nonperformance by the other parties, are substantially smaller. EOG evaluates its exposure to all counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk. At December 31, 2004, EOG's net accounts receivable balance related to United States and Canada hydrocarbon sales included two receivable balances, each of which constituted 11% of the total balance. These receivables were due from two integrated oil and gas companies. The related amounts were collected during early 2005. The amounts due from an integrated oil and gas company and a utility company at December 31, 2003, which approximated 14% and 11%, respectively, of the United States and Canada net accounts receivable balance, were collected during early 2004. No other individual purchaser accounted for 10% or more of the United States and Canada net accounts receivable balance at December 31, 2004 and 2003. At December 31, 2004, EOG had an allowance for doubtful accounts of $21 million, of which $19 million is associated with the Enron bankruptcies recorded in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2004 and 2003 result from hydrocarbon sales and/or joint interest billings to third party companies including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer or joint interest owner, EOG analyzes the entity's net worth, cash flows, earnings, and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2004, credit losses incurred on receivables by EOG have been immaterial.

12. ACCOUNTING FOR CERTAIN LONG-LIVED ASSETS

EOG reviews its oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. During 2004, 2003 and 2002, such reviews indicated that unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows due primarily to downward reserve revisions for certain producing fields. As a result, during 2004, 2003 and 2002, EOG recorded in Impairments pre-tax charges of $17 million, $21 million and $30 million, respectively, in the United States operating segment and $8 million, $4 million and $0, respectively, in the Canada operating segment. The carrying values for assets determined to be impaired were adjusted to estimated fair values based on projected future net cash flows discounted using EOG's risk-adjusted discount rate. Amortization expenses of acquisition costs of unproved properties, including amortization of capitalized interest, were $57 million, $64 million and $38 million for 2004, 2003 and 2002, respectively.

13. ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

EOG adopted SFAS No. 143 – "Accounting for Asset Retirement Obligations" on January 1, 2003. The adoption of the statement resulted in an after-tax charge of $7.1 million, which was reported in the first quarter of 2003 as Cumulative Effect of Change in Accounting Principle. The following table presents the reconciliation of the beginning and ending aggregate carrying amount of short-term and long-term legal obligations associated with the retirement of oil and gas properties pursuant to SFAS No. 143 for 2004 (in thousands):

	Asset Retirement Obligations		
	Short-Term	Long-Term	Total
Balance at December 31, 2003	$5,320	$118,624	$123,944
Liabilities Incurred	2,060	14,728	16,788
Liabilities Settled	(4,831)	(5,422)	(10,253)
Accretion	164	5,423	5,587
Revision	1,333	744	2,077
Reclassification	2,894	(2,894)	-
Foreign Currency Translation	30	586	616
Balance at December 31, 2004	**$6,970**	**$131,789**	**$138,759**

Pro forma net income and earnings per share are not presented for the comparable period in 2002 because the pro forma application of SFAS No. 143 to the prior period would not result in pro forma net income and earnings per share materially different from the actual amounts reported for the period in the accompanying Consolidated Statements of Income.

14. INVESTMENT IN CARIBBEAN NITROGEN COMPANY LIMITED AND NITROGEN (2000) UNLIMITED

EOG, through certain wholly owned subsidiaries, owns equity interests in two Trinidadian companies: CNCL and N2000. During the first quarters of 2003 and 2004, EOG completed separate share sale agreements whereby a portion of the EOG subsidiaries' shareholdings in CNCL and N2000 was sold to a third party energy company. The sales left EOG with equity interests of 12% in CNCL and 23% in N2000 and did not result in any gain or loss.

In February 2005, a portion of EOG's shareholdings in N2000 was sold to a subsidiary of one of the other shareholders. The sale resulted in a pre-tax gain of approximately $2 million. EOG's equity interest in N2000 is now 10%.

The other shareholders in CNCL are Ferrostaal AG, Clico Energy Company Limited, KBRDC CNC (Cayman) Ltd. and Koch CNC (Nevis) LLC. At December 31, 2004, investment in CNCL was $15 million. CNCL commenced production in June 2002, and at December 31, 2004, was producing approximately 1,850 metric tons of ammonia daily. At December 31, 2004, CNCL had a long-term debt balance of $203 million, which is non-recourse to CNCL's shareholders. EOG will be liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of CNCL up to $30 million, approximately $4 million of which is net to EOG's interest. The Shareholders' Agreement requires the consent of the holders of 90% or more of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of CNCL and therefore, it accounts for the investment using the equity method. During 2004, EOG recognized equity income of $5 million and received cash dividends of $5 million from CNCL.

The other shareholders in N2000 are FS Petrochemicals (St. Kitts) Limited, CE Limited, KBRDC Nitrogen 2000 (St. Lucia) Ltd. and Koch N2000 (Nevis) LLC. At December 31, 2004, investment in N2000 was $26 million. N2000 commenced production in August 2004, and at December 31, 2004, was producing approximately 1,950 metric tons of ammonia daily. At December 31, 2004, N2000 had a long-term debt balance of $228 million, which is non-recourse to N2000's shareholders. At December 31, 2004, EOG was liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $30 million, approximately $7 million of which is net to EOG's interest. The Shareholders' Agreement requires the consent of the holders of 100% of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of N2000 and therefore, it accounts for the investment using the equity method. During 2004, EOG recognized equity income of $6 million.

15. PROPERTY ACQUISITIONS

On October 1, 2003, a Canadian subsidiary of EOG closed an asset purchase of natural gas properties in the Wintering Hills, Drumheller East and Twining areas of southeast Alberta from a subsidiary of Husky Energy Inc. for approximately US$320 million. These properties are essentially adjacent to existing EOG operations or are properties in which EOG already had a working interest. The transaction was partially funded by commercial paper borrowings of US$140.5 million on October 1, 2003. The remainder of the purchase price, US$179.5 million, was funded by EOG's available cash balance. Subsequent to the closing, the purchase price was reduced by exercised preferential rights on the properties which totaled approximately US$5 million. In late December 2003, a Canadian subsidiary of EOG closed another property acquisition for US$46 million.

OIL AND GAS PRODUCING ACTIVITIES

The following disclosures are made in accordance with SFAS No. 69 - "Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil and natural gas 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. Consequently, material revisions (upward or downward) 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 significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

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

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and EOG's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause EOG's share of future production from Canadian reserves to be materially different from that presented.

Estimates of proved and proved developed reserves at December 31, 2004, 2003 and 2002 were based on studies performed by the engineering staff of EOG for all reserves. Opinions by DeGolyer and MacNaughton (D&M), independent petroleum consultants, for the years ended December 31, 2004, 2003 and 2002 covered producing areas containing 77%, 72% and 73%, respectively, of proved reserves of EOG on a net-equivalent-cubic-feet-of-gas basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's engineering staff for the properties reviewed by D&M, when compared in total on a net-equivalent-cubic-feet-of-gas basis, do not differ materially from the estimates prepared by D&M. Such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the engineering staff of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG.

No major discovery or other favorable or adverse event subsequent to December 31, 2004 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

The following table sets forth EOG's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 2004, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the engineering staff of EOG.

Net Proved Reserves	United States	Canada	Trinidad	United Kingdom	TOTAL
Natural Gas (Bcf)					
Net proved reserves at December 31, 2001	2,007.3	644.1	1,145.1	-	3,796.5
Revisions of previous estimates	9.4	4.7	(21.7)	-	(7.6)
Purchases in place	9.9	102.9	-	-	112.8
Extensions, discoveries and other additions	217.0	83.9	232.4	-	533.3
Sales in place	(0.8)	(1.5)	-	-	(2.3)
Production	(236.6)	(56.2)	(49.3)	-	(342.1)
Net proved reserves at December 31, 2002	2,006.2	777.9	1,306.5	-	4,090.6
Revisions of previous estimates	(24.9)	(18.5)	(74.9)	-	(118.3)
Purchases in place	43.9	361.0	-	-	404.9
Extensions, discoveries and other additions	345.5	118.3	129.3	59.2	652.3
Sales in place	(30.8)	-	-	-	(30.8)
Production	(238.3)	(60.2)	(55.4)	-	(353.9)
Net proved reserves at December 31, 2003	2,101.6	1,178.5	1,305.5	59.2	4,644.8
Revisions of previous estimates	**(62.8)**	**(26.8)**	**34.2**	**-**	**(55.4)**
Purchases in place	**44.4**	**16.6**	**-**	**-**	**61.0**
Extensions, discoveries and other additions	**537.8**	**208.0**	**37.9**	**-**	**783.7**
Sales in place	**(1.3)**	**(0.6)**	**-**	**-**	**(1.9)**
Production	**(237.2)**	**(77.4)**	**(68.2)**	**(2.4)**	**(385.2)**
Net proved reserves at December 31, 2004	**2,382.5**	**1,298.3**	**1,309.4**	**56.8**	**5,047.0**
Liquids (MBbl)					
Net proved reserves at December 31, 2001	52,383	6,652	13,099	-	72,134
Revisions of previous estimates	3,543	396	(572)	-	3,367
Purchases in place	624	865	-	-	1,489
Extensions, discoveries and other additions	14,763	279	3,041	-	18,083
Sales in place	(33)	-	-	-	(33)
Production	(7,925)	(1,026)	(874)	-	(9,825)
Net proved reserves at December 31, 2002	63,355	7,166	14,694	-	85,215
Revisions of previous estimates	1,487	214	(1,120)	-	581
Purchases in place	738	1,379	-	-	2,117
Extensions, discoveries and other additions	15,669	598	1,212	84	17,563
Sales in place	(344)	-	-	-	(344)
Production	(7,897)	(1,091)	(881)	-	(9,869)
Net proved reserves at December 31, 2003	73,008	8,266	13,905	84	95,263
Revisions of previous estimates	**2,649**	**(116)**	**3,417**	**69**	**6,019**
Purchases in place	**157**	**1**	**-**	**-**	**158**
Extensions, discoveries and other additions	**9,859**	**920**	**229**	**-**	**11,008**
Sales in place	**(411)**	**(14)**	**-**	**-**	**(425)**
Production	**(9,474)**	**(1,290)**	**(1,291)**	**(9)**	**(12,064)**
Net proved reserves at December 31, 2004	**75,788**	**7,767**	**16,260**	**144**	**99,959**

	United States	Canada	Trinidad	United Kingdom	TOTAL
Bcf Equivalent (Bcfe)					
Net proved reserves at December 31, 2001	2,321.6	684.0	1,223.7	-	4,229.3
Revisions of previous estimates	30.7	7.1	(25.1)	-	12.7
Purchases in place	13.6	108.1	-	-	121.7
Extensions, discoveries and other additions	305.6	85.6	250.6	-	641.8
Sales in place	(1.0)	(1.5)	-	-	(2.5)
Production	(284.2)	(62.4)	(54.5)	-	(401.1)
Net proved reserves at December 31, 2002	2,386.3	820.9	1,394.7	-	4,601.9
Revisions of previous estimates	(15.9)	(17.2)	(81.7)	-	(114.8)
Purchases in place	48.3	369.3	-	-	417.6
Extensions, discoveries and other additions	439.6	121.8	136.5	59.7	757.6
Sales in place	(32.9)	-	-	-	(32.9)
Production	(285.7)	(66.7)	(60.7)	-	(413.1)
Net proved reserves at December 31, 2003	2,539.7	1,228.1	1,388.8	59.7	5,216.3
Revisions of previous estimates	**(47.0)**	**(27.5)**	**54.8**	**0.4**	**(19.3)**
Purchases in place	**45.4**	**16.6**	**-**	**-**	**62.0**
Extensions, discoveries and other additions	**597.0**	**213.5**	**39.3**	**-**	**849.8**
Sales in place	**(3.8)**	**(0.7)**	**-**	**-**	**(4.5)**
Production	**(294.1)**	**(85.1)**	**(75.9)**	**(2.5)**	**(457.6)**
Net proved reserves at December 31, 2004	**2,837.2**	**1,344.9**	**1,407.0**	**57.6**	**5,646.7**

Net Proved Developed Reserves at:	United States	Canada	Trinidad	United Kingdom	TOTAL
Natural Gas (Bcf)					
December 31, 2001	1,588.4	587.6	620.6	-	2,796.
December 31, 2002	1,658.7	683.3	555.2	-	2,897.2
December 31, 2003	1,749.3	889.2	429.9	-	3,068.4
December 31, 2004	**1,855.7**	**1,070.1**	**760.9**	**56.8**	**3,743.5**
Liquids (MBbl)					
December 31, 2001	41,205	6,532	8,435	-	56,172
December 31, 2002	47,476	7,045	7,135	-	61,656
December 31, 2003	56,321	7,995	5,229	-	69,545
December 31, 2004	**60,478**	**7,414**	**10,874**	**144**	**78,910**
Bcf Equivalents (Bcfe)					
December 31, 2001	1,835.7	626.8	671.1	-	3,133.6
December 31, 2002	1,943.6	725.5	598.0	-	3,267.1
December 31, 2003	2,087.3	937.2	461.2	-	3,485.7
December 31, 2004	**2,218.5**	**1,114.7**	**826.2**	**57.6**	**4,217.0**

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's natural gas and crude oil producing activities at December 31 of the years indicated as follows:

	2004	2003
Proved Properties	**$9,307,422**	$7,990,675
Unproved Properties	**291,854**	198,387
Total	**9,599,276**	8,189,062
Accumulated Depreciation, Depletion and Amortization	**(4,497,673)**	(3,940,145)
Net Capitalized Costs	**$5,101,603**	$4,248,917

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in SFAS No. 19 - "Financial Accounting and Reporting by Oil and Gas Producing Companies" and SFAS No. 143 - "Accounting for Asset Retirement Obligations."

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire property.

Exploration costs include additions to exploration wells including those in progress and exploration expenses.

Development costs include additions to production facilities and equipment and additions to development wells including those in progress.

The following tables set forth costs incurred related to EOG's oil and gas activities for the years ended December 31:

	United States	Canada	Trinidad	United Kingdom	Other	TOTAL
2004						
Acquisition Costs of Properties						
Unproved	**$ 129,230**	**$ 13,490**	**$ 74**	**$ -**	**$ -**	**$ 142,794**
Proved	**47,653**	**4,587**	**-**	**-**	**-**	**52,240**
Subtotal	**176,883**	**18,077**	**74**	**-**	**-**	**195,034**
Exploration Costs	**212,324**	**27,771**	**35,227**	**27,818**	**3,443**	**306,583**
Development Costs	**660,799**	**270,435**	**46,864**	**30,910**	**-**	**1,009,008**
Subtotal	**1,050,006**	**316,283**	**82,165**	**58,728**	**3,443**	**1,510,625**
Asset Retirement Costs(1)	**5,644**	**6,610**	**1,754**	**2,223**	**-**	**16,231**
Deferred Income Tax on Acquired Properties	**-**	**(16,834)**	**-**	**-**	**-**	**(16,834)**
Total	**$ 1,055,650**	**$ 306,059**	**$ 83,919**	**$ 60,951**	**$ 3,443**	**$ 1,510,022**
2003						
Acquisition Costs of Properties						
Unproved	$ 43,890	$ 14,536	$ 172	$ -	$ -	$ 58,598
Proved	18,347	386,532	-	-	-	404,879
Subtotal	62,237	401,068	172	-	-	463,477
Exploration Costs	145,104	15,429	20,517	20,958	4,664	206,672
Development Costs	480,257	145,539	23,140	2,812	-	651,748
Subtotal	687,598	562,036	43,829	23,770	4,664	1,321,897
Asset Retirement Costs(1)	8,167	3,552	-	-	-	11,719
Total	$ 695,765	$ 565,588	$ 43,829	$ 23,770	$ 4,664	$ 1,333,616
2002						
Acquisition Costs of Properties						
Unproved	$ 28,232	$ 4,754	$ 5,629	$ -	$ -	$ 38,615
Proved	22,589	48,487	-	-	-	71,076
Subtotal	50,821	53,241	5,629	-	-	109,691
Exploration Costs	120,058	25,866	18,117	-	2,384	166,425
Development Costs	423,436	107,952	13,600	-	-	544,988
Subtotal	594,315	187,059	37,346	-	2,384	821,104
Deferred Income Tax on Acquired Properties	-	14,938	-	-	-	14,938
Total(2)	$ 594,315	$ 201,997	$ 37,346	$ -	$ 2,384	$ 836,042

(1) The Asset Retirement Costs for the United States are netted with $1 million net gains recognized upon settlement of asset retirement obligations for each of 2004 and 2003. Asset Retirement Costs for 2003 do not include the cumulative effect of adoption of SFAS No. 143 - "Accounting for Asset Retirement Obligations" on January 1, 2003.

(2) Pro forma total costs incurred for 2002 are not presented as the pro forma application of SFAS No. 143 to the prior period would not result in pro forma total expenditures materially different from the actual amount reported.

Results of Operations for Oil and Gas Producing Activities(1). The following tables set forth results of operations for oil and gas producing activities for the years ended December 31:

	United States	Canada	Trinidad	United Kingdom	Other(2)	TOTAL
2004						
Natural Gas, Crude Oil and Condensate Revenues	**$ 1,687,646**	**$ 448,346**	**$ 153,377**	**$ 12,972**	**$ -**	**$ 2,302,341**
Other, Net	**2,128**	**205**	**-**	**-**	**-**	**2,333**
Total	**1,689,774**	**448,551**	**153,377**	**12,972**	**-**	**2,304,674**
Exploration Expenses	**71,823**	**10,264**	**7,109**	**4,745**	**-**	**93,941**
Dry Hole Expenses	**45,164**	**11,447**	**15,851**	**19,680**	**-**	**92,142**
Production Costs	**294,338**	**83,527**	**14,670**	**1,790**	**-**	**394,325**
Impairments	**68,309**	**13,221**	**-**	**-**	**-**	**81,530**
Depreciation, Depletion and Amortization	**382,718**	**99,879**	**20,022**	**1,784**	**-**	**504,403**
Income (Loss) Before Income Taxes	**827,422**	**230,213**	**95,725**	**(15,027)**	**-**	**1,138,333**
Income Tax Provision (Benefit)	**295,063**	**75,146**	**33,953**	**(7,230)**	**-**	**396,932**
Results of Operations	**$ 532,359**	**$ 155,067**	**$ 61,772**	**$ (7,797)**	**$ -**	**$ 741,401**
2003						
Natural Gas, Crude Oil and Condensate Revenues	$ 1,410,946	$ 309,336	$ 100,112	$ -	$ -	$ 1,820,394
Other, Net	4,613	82	-	-	-	4,695
Total	1,415,559	309,418	100,112	-	-	1,825,089
Exploration Expenses	65,885	5,726	3,997	739	11	76,358
Dry Hole Expenses	20,706	4,139	7,890	8,421	-	41,156
Production Costs	219,447	58,249	11,363	51	2	289,112
Impairments	81,661	7,473	-	-	(1)	89,133
Depreciation, Depletion and Amortization	359,439	66,334	16,070	-	-	441,843
Income (Loss) Before Income Taxes	668,421	167,497	60,792	(9,211)	(12)	887,487
Income Tax Provision (Benefit)	239,534	61,928	24,661	(3,673)	(5)	322,445
Results of Operations	$ 428,887	$ 105,569	$ 36,131	$ (5,538)	$ (7)	$ 565,042
2002						
Natural Gas, Crude Oil and Condensate Revenues	$ 891,991	$ 170,875	$ 79,551	$ -	$ 21	$ 1,142,438
Other, Net	2,521	(1,769)	-	-	-	752
Total	894,512	169,106	79,551	-	21	1,143,190
Exploration Expenses	52,830	5,529	1,656	152	61	60,228
Dry Hole Expenses	26,107	20,642	-	-	-	46,749
Production Costs	186,041	48,261	9,977	64	7	244,350
Impairments	65,813	2,619	-	-	(2)	68,430
Depreciation, Depletion and Amortization	334,318	49,622	14,085	-	11	398,036
Income (Loss) Before Income Taxes	229,403	42,433	53,833	(216)	(56)	325,397
Income Tax Provision (Benefit)	82,136	10,319	23,971	(70)	(20)	116,336
Results of Operations	$ 147,267	$ 32,114	$ 29,862	$ (146)	$ (36)	$ 209,061

(1) Excludes gains or losses on mark-to-market commodity derivative contracts, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2004.

(2) Other includes other international operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of EOG. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of 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 EOG.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's crude oil and natural gas reserves for the years ended December 31:

	United States	Canada	Trinidad	United Kingdom	TOTAL
2004					
Future cash inflows	**$ 17,044,764**	**$ 7,530,192**	**$ 3,419,365**	**$ 312,843**	**$ 28,307,164**
Future production costs	**(4,485,711)**	**(2,436,056)**	**(486,892)**	**(77,245)**	**(7,485,904)**
Future development costs	**(873,309)**	**(281,233)**	**(218,784)**	**(2,422)**	**(1,375,748)**
Future net cash flows before income taxes	**11,685,744**	**4,812,903**	**2,713,689**	**233,176**	**19,445,512**
Future income taxes	**(3,583,378)**	**(1,295,774)**	**(986,977)**	**(60,010)**	**(5,926,139)**
Future net cash flows	**8,102,366**	**3,517,129**	**1,726,712**	**173,166**	**13,519,373**
Discount to present value at 10% annual rate	**(3,795,487)**	**(1,570,232)**	**(809,757)**	**(25,919)**	**(6,201,395)**
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$ 4,306,879**	**$ 1,946,897**	**$ 916,955**	**$ 147,247**	**$ 7,317,978**
2003					
Future cash inflows	$ 14,030,539	$ 6,221,171	$ 2,995,951	$ 320,427	$ 23,568,088
Future production costs	(3,026,650)	(1,289,592)	(449,200)	(47,524)	(4,812,966)
Future development costs	(524,401)	(200,324)	(228,504)	(21,289)	(974,518)
Future net cash flows before income taxes	10,479,488	4,731,255	2,318,247	251,614	17,780,604
Future income taxes	(3,382,125)	(1,376,955)	(786,418)	(96,896)	(5,642,394)
Future net cash flows	7,097,363	3,354,300	1,531,829	154,718	12,138,210
Discount to present value at 10% annual rate	(3,393,605)	(1,610,085)	(778,985)	(41,420)	(5,824,095)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 3,703,758	$ 1,744,215	$ 752,844	$ 113,298	$ 6,314,115
2002					
Future cash inflows	$ 9,826,571	$ 2,989,000	$ 2,303,930	$ -	$ 15,119,501
Future production costs	(2,212,357)	(586,166)	(433,029)	-	(3,231,552)
Future development costs	(359,787)	(43,876)	(177,275)	-	(580,938)
Future net cash flows before income taxes	7,254,427	2,358,958	1,693,626	-	11,307,011
Future income taxes	(2,214,072)	(653,425)	(558,788)	-	(3,426,285)
Future net cash flows	5,040,355	1,705,533	1,134,838	-	7,880,726
Discount to present value at 10% annual rate	(2,265,700)	(766,567)	(629,024)	-	(3,661,291)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,774,655	$ 938,966	$ 505,814	$ -	$ 4,219,435

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2004:

	United States	Canada	Trinidad	United Kingdom	TOTAL
December 31, 2001	$ 1,710,026	$ 470,477	$ 346,886	$ -	$ 2,527,389
Sales and transfers of oil and gas produced, net of production costs	(705,938)	(122,614)	(69,574)	-	(898,126)
Net changes in prices and production costs	1,561,946	460,977	223,614	-	2,246,537
Extensions, discoveries, additions and improved recovery net of related costs	499,257	123,700	110,415	-	733,372
Development costs incurred	84,300	18,100	13,600	-	116,000
Revisions of estimated development cost	35,255	(11,418)	(20,574)	-	3,263
Revisions of previous quantity estimates	51,227	11,470	(15,634)	-	47,063
Accretion of discount	200,701	59,594	48,622	-	308,917
Net change in income taxes	(692,670)	(135,888)	(87,229)	-	(915,787)
Purchases of reserves in place	28,851	117,958	-	-	146,809
Sales of reserves in place	(715)	(2,827)	-	-	(3,542)
Changes in timing and other	2,415	(50,563)	(44,312)	-	(92,460)
December 31, 2002	2,774,655	938,966	505,814	-	4,219,435
Sales and transfers of oil and gas produced, net of production costs	(1,191,450)	(251,070)	(88,749)	-	(1,531,269)
Net changes in prices and production costs	1,334,817	422,754	294,570	-	2,052,141
Extensions, discoveries, additions and improved recovery net of related costs	916,653	227,632	93,754	182,581	1,420,620
Development costs incurred	103,200	22,600	23,100	-	148,900
Revisions of estimated development cost	(34,688)	(45,591)	(29,415)	-	(109,694)
Revisions of previous quantity estimates	(35,537)	(34,700)	(65,239)	-	(135,476)
Accretion of discount	376,431	120,032	73,237	-	569,700
Net change in income taxes	(520,575)	(240,253)	(145,698)	(69,283)	(975,809)
Purchases of reserves in place	94,482	547,011	-	-	641,493
Sales of reserves in place	(63,136)	-	-	-	(63,136)
Changes in timing and other	(51,094)	36,834	91,470	-	77,210
December 31, 2003	3,703,758	1,744,215	752,844	113,298	6,314,115
Sales and transfers of oil and gas produced, net of production costs	**(1,393,308)**	**(364,819)**	**(138,707)**	**(11,182)**	**(1,908,016)**
Net changes in prices and production costs	**104,059**	**(148,876)**	**181,837**	**(20,213)**	**116,807**
Extensions, discoveries, additions and improved recovery net of related costs	**1,247,934**	**385,547**	**8,564**	**-**	**1,642,045**
Development costs incurred	**130,000**	**88,900**	**97,000**	**9,500**	**325,400**
Revisions of estimated development cost	**77,986**	**8,058**	**(31,237)**	**5,138**	**59,945**
Revisions of previous quantity estimates	**(101,976)**	**(48,656)**	**56,372**	**1,252**	**(93,008)**
Accretion of discount	**521,398**	**224,582**	**112,510**	**18,258**	**876,748**
Net change in income taxes	**(143,615)**	**23,315**	**(124,614)**	**26,552**	**(218,362)**
Purchases of reserves in place	**79,703**	**15,543**	**-**	**-**	**95,246**
Sales of reserves in place	**(10,307)**	**(1,776)**	**-**	**-**	**(12,083)**
Changes in timing and other	**91,247**	**20,864**	**2,386**	**4,644**	**119,141**
December 31, 2004	**$ 4,306,879**	**$ 1,946,897**	**$ 916,955**	**$ 147,247**	**$ 7,317,978**

Unaudited Quarterly Financial Information

The following table presents unaudited quarterly financial information for 2004 and 2003:

(In Thousands, Except Per Share Amounts)	Quarter Ended Mar 31	Jun 30	Sep 30	Dec 31
2004				
Net Operating Revenues	**$ 464,320**	**$ 519,021**	**$ 594,230**	**$ 693,654**
Operating Income	**$ 171,436**	**$ 226,736**	**$ 274,500**	**$ 306,523**
Income Before Income Taxes	**$ 152,024**	**$ 212,745**	**$ 262,343**	**$ 298,900**
Income Tax Provision	**51,171**	**67,808**	**90,033**	**92,145**
Net Income	**100,853**	**144,937**	**172,310**	**206,755**
Preferred Stock Dividends	**2,758**	**2,758**	**2,758**	**2,618**
Net Income Available to Common	**$ 98,095**	**$ 142,179**	**$ 169,552**	**$ 204,137**
Net Income Per Share Available to Common				
Basic(1)	**$ 0.85**	**$ 1.22**	**$ 1.44**	**$ 1.73**
Diluted(1)	**$ 0.83**	**$ 1.20**	**$ 1.42**	**$ 1.69**
Average Number of Common Shares				
Basic	**115,645**	**116,388**	**117,411**	**118,070**
Diluted	**117,621**	**118,709**	**119,677**	**120,556**
2003				
Net Operating Revenues	$ 464,669	$ 424,754	$ 458,724	$ 396,528
Operating Income	$ 226,129	$ 176,868	$ 193,312	$ 101,005
Income Before Income Taxes	$ 210,963	$ 165,741	$ 179,604	$ 97,568
Income Tax Provision	74,407	56,950	62,185	23,058
Net Income Before Cumulative Effect of Change in Accounting Principle	136,556	108,791	117,419	74,510
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(7,131)	-	-	-
Net Income	129,425	108,791	117,419	74,510
Preferred Stock Dividends	2,758	2,758	2,758	2,758
Net Income Available to Common	$ 126,667	$ 106,033	$ 114,661	$ 71,752
Net Income Per Share				
Basic(1)				
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 1.17	$ 0.93	$ 1.00	$ 0.62
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 1.11	$ 0.93	$ 1.00	$ 0.62
Diluted(1)				
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$ 1.15	$ 0.91	$ 0.99	$ 0.61
Cumulative Effect of Change in Accounting Principle, Net of Income Tax	(0.06)	-	-	-
Net Income Per Share Available to Common	$ 1.09	$ 0.91	$ 0.99	$ 0.61
Average Number of Common Shares				
Basic	114,441	114,382	114,616	114,893
Diluted	116,224	116,131	116,370	117,209

(1) The sum of net income per share available to common may not agree with total year net income per share available to common as each quarterly computation is based on the weighted average of common shares outstanding.

SELECTED FINANCIAL DATA

(In Thousands, Except Per Share Amounts)	Year Ended December 31		
	2004	2003	2002
Statement of Income Data:			
Net Operating Revenues	**$ 2,271,225**	$ 1,744,675	$ 1,094,682
Operating Income	**979,195**	697,314	180,977
Net Income Before Cumulative Effect of Change in Accounting Principle	**$ 624,855**	$ 437,276	$ 87,173
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	**-**	(7,131)	-
Net Income	**624,855**	430,145	87,173
Preferred Stock Dividends	**10,892**	11,032	11,032
Net Income Available to Common	**$ 613,963**	$ 419,113	$ 76,141
Net Income Per Share Available to Common			
Basic			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	**$ 5.25**	$ 3.72	$ 0.66
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	**-**	(0.06)	-
Net Income Per Share Available to Common	**$ 5.25**	$ 3.66	$ 0.66
Diluted			
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	**$ 5.15**	$ 3.66	$ 0.65
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	**-**	(0.06)	-
Net Income Per Share Available to Common	**$ 5.15**	$ 3.60	$ 0.65
Average Number of Common Shares			
Basic	**116,876**	114,597	115,335
Diluted	**119,188**	116,519	117,245

(1) EOG adopted Statement of Financial Accounting Standards (SFAS) No. 143 - "Accounting for Asset Retirement Obligations" on January 1, 2003. Pro forma net income for 2002 is not presented since the pro forma application of SFAS No. 143 to the prior periods would not result in pro forma net income materially different from the actual amount reported.

(In Thousands)	At December 31		
	2004	2003	2002
Balance Sheet Data:			
Net Oil and Gas Properties	**$ 5,101,603**	$ 4,248,917	$ 3,321,548
Total Assets	**5,798,923**	4,749,015	3,813,568
Long-Term Debt	**1,077,622**	1,108,872	1,145,132
Shareholders' Equity	**2,945,424**	2,223,381	1,672,395

QUARTERLY STOCK DATA AND RELATED SHAREHOLDER MATTERS

The following table sets forth, for the periods indicated, the high and low sales prices per share for the common stock of EOG, as reported on the New York Stock Exchange Composite Tape, and the amount of common stock dividend declared per share. The information shown in the following table is not adjusted for the 2005 stock split discussed below.

	Price Range		Dividend
	High	Low	Declared
2004			
First Quarter	**$ 47.45**	**$ 42.45**	**$ 0.06**
Second Quarter	**63.69**	**45.32**	**0.06**
Third Quarter	**66.87**	**55.20**	**0.06**
Fourth Quarter	**76.50**	**64.15**	**0.06**
2003			
First Quarter	$ 42.83	$ 35.70	$ 0.04
Second Quarter	45.56	36.56	0.05
Third Quarter	42.87	37.70	0.05
Fourth Quarter	47.52	40.85	0.05

On February 2, 2005, EOG announced that the Board of Directors had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and to be issued on March 1, 2005. In addition, the Board increased the quarterly cash dividend on the common stock by 33%, resulting in a quarterly cash dividend of $0.08 per share pre-split or $0.04 per share post-split. The stock split was the second stock split in the history of EOG. On June 15, 1994, EOG also effected a two-for-one stock split in the form of a stock dividend.

As of February 24, 2005, there were approximately 270 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 77,750 beneficial owners of EOG's common stock, including shares held in street name.

EOG currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, the financial condition, funds from operations, level of exploration, exploitation and development expenditure opportunities and future business prospects of EOG.

RECONCILIATION SCHEDULES

(Unaudited; In Millions, Except Ratio and Share Information)

Below are supporting schedules and definitions for certain quantitative measures used in the Letter to Shareholders:

	1999	2000	2001	2002	2003	2004
Return on Equity (ROE)						
Shareholders' Equity	$ 1,130	$ 1,381	$ 1,643	$ 1,672	$ 2,223	**$ 2,945**
Less: Preferred Stock	(147)	(147)	(148)	(148)	(148)	**(99)**
Common Shareholders' Equity (Non-GAAP)	$ 983	$ 1,234	$ 1,495	$ 1,524	$ 2,075	**$ 2,846**
Average Common Shareholders' Equity - (a)		$ 1,109	$ 1,365	$ 1,510	$ 1,800	**$ 2,461**
Net Income Available to Common - (b)		$ 386	$ 388	$ 76	$ 419	**$ 614**
ROE - (b) / (a)		35%	28%	5%	23%	**25%***
Average ROE 2000 - 2004						**23%***
Return on Capital Employed (ROCE)						
Interest Expense		$ 61	$ 45	$ 60	$ 59	**$ 63**
Tax Benefit Imputed (based on 35%)		(21)	(16)	(21)	(21)	**(22)**
After Tax Interest Expense (Non-GAAP) - (a)		$ 40	$ 29	$ 39	$ 38	**$ 41**
Net Income - (b)		$ 397	$ 399	$ 87	$ 430	**$ 625**
Shareholders' Equity	$ 1,130	$ 1,381	$ 1,643	$ 1,672	$ 2,223	**$ 2,945**
Net Debt						
Long-Term Debt	990	859	856	1,145	1,109	**1,078**
Less: Cash	(25)	(20)	(3)	(10)	(4)	**(21)**
Total Capitalization	$ 2,095	$ 2,220	$ 2,496	$ 2,807	$ 3,328	**$ 4,002**
Average Total Capitalization - (c)		$ 2,157	$ 2,358	$ 2,652	$ 3,068	**$ 3,665**
ROCE - [(a) + (b)] / (c)		20%	18%	5%	15%	**18%***
Average ROCE 2000 - 2004						**15%***

Debt-to-Total Capitalization Ratio

As used in this ratio, Total Capitalization is the sum of Long-Term Debt and Shareholders' Equity.

Return to Shareholders

Return to Shareholders represents the total return after reinvesting all dividends back into the share and the appreciation in stock price during the period. The total return is expressed as a percentage of the stock price at the beginning of the period.

CERTIFICATIONS

In 2004, EOG's chief executive officer (CEO) provided to the New York Stock Exchange the annual CEO certification regarding EOG's compliance with the New York Stock Exchange's corporate governance listing standards. In addition, EOG's CEO and EOG's principal financial officer filed with the U.S. Securities and Exchange Commission all required certifications regarding the quality of EOG's public disclosures in its reports for the fiscal year 2004.

GLOSSARY OF TERMS

Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
CNCL	Caribbean Nitrogen Company Limited
$/Bbl	Dollars per barrel
$/Mcf	Dollars per thousand cubic feet
$/MMBtu	Dollars per million British thermal units
LNG	Liquefied Natural Gas
MBbl	Thousand barrels
MBbld	Thousand barrels per day
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MMBtu	Million British thermal units
MMBtud	Million British thermal units per day
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMcfe	Million cubic feet equivalent
MMcfed	Million cubic feet equivalent per day
N2000	Nitrogen (2000) Unlimited
NGC	National Gas Company of Trinidad and Tobago
NYMEX	New York Mercantile Exchange
ROCE	Return on Capital Employed
ROE	Return on Equity
S&P	Standard and Poor's
SECC	South East Coast Consortium
Tcfe	Trillion cubic feet equivalent

OFFICERS AND DIRECTORS

Directors

George A. Alcorn[1]
Houston, Texas
President, Alcorn Exploration, Inc.

Charles R. Crisp[2]
Houston, Texas
Investments

Mark G. Papa
Chairman and Chief Executive Officer
EOG Resources, Inc.

Edmund P. Segner, III
President and Chief of Staff
EOG Resources, Inc.

William D. Stevens[3]
Houston, Texas
Retired

H. Leighton Steward[4]
Boerne, Texas
Author-Partner, Sugar Busters LLC

Donald F. Textor[5]
Locust Valley, New York
Portfolio Manager, Dorset Energy Fund and Partner, Knott Partners LLC

Frank G. Wisner[6]
New York, New York
Vice Chairman
American International Group, Inc.

Executive Committee

Mark G. Papa
Chairman and Chief Executive Officer

Edmund P. Segner, III
President and Chief of Staff

Loren M. Leiker
Executive Vice President,
Exploration and Development

Gary L. Thomas
Executive Vice President, Operations

Barry Hunsaker, Jr.
Senior Vice President and General Counsel

Sandeep Bhakhri
Vice President and Chief Information Officer

Officers

(including key subsidiaries)

Lewis Chandler, Jr.
Senior Vice President, Law

Steven B. Coleman
Senior Vice President and General Manager, Tyler

Kurt D. Doerr
Senior Vice President and General Manager, Denver

Lawrence E. Fenwick
Senior Vice President and General Manager, EOG Resources Canada Inc.

Robert K. Garrison
Senior Vice President and General Manager, Corpus Christi

William R. Thomas
Senior Vice President and General Manager, Fort Worth

William E. Albrecht
Vice President, Acquisitions and Engineering

Maire A. Baldwin
Vice President, Investor Relations

Ben B. Boyd
Vice President, Accounting,
EOG Resources International, Inc.

Gerald R. Colley
Vice President and General Manager, International
President, EOG Resources International, Inc.

Phil C. DeLozier
Vice President, Business Development

Timothy K. Driggers
Vice President and Chief Accounting Officer

Patricia L. Edwards
Vice President, Human Resources, Administration and Corporate Secretary

Kevin S. Hanzel
Vice President, Audit

Andrew N. Hoyle
Vice President, Marketing and Regulatory Affairs

Olaf A. C. Karlsen
General Manager, EOG Resources United Kingdom Limited

Lindell L. Looger
Vice President and General Manager,
EOG Resources Trinidad Limited

Tony C. Maranto
Vice President and General Manager,
Oklahoma City

Richard A. Ott
Vice President, Tax

Earl J. Ritchie, Jr.
Vice President and General Manager,
Offshore

Gary L. Smith
Vice President and General Manager,
Pittsburgh

Steven E. Weatherl
Vice President and General Manager,
Midland

Ronnie L. Adams
Controller, Land Administration

Ann D. Janssen
Controller, Financial Reporting and Planning

Joseph C. Landry
Controller, Operations Accounting

Helen Y. Lim
Treasurer

(1) Chairman, Compensation Committee; Member, Audit, Corporate Governance and Nominating Committees; 2004 Presiding Director
(2) Chairman, Nominating Committee; Member, Audit, Compensation and Corporate Governance Committees
(3) Member, Audit, Compensation, Corporate Governance and Nominating Committees
(4) Member, Audit, Compensation, Corporate Governance and Nominating Committees; 2005 Presiding Director
(5) Chairman, Audit Committee; Member, Compensation, Corporate Governance and Nominating Committees
(6) Chairman, Corporate Governance Committee; Member, Audit, Compensation and Nominating Committees

SHAREHOLDER INFORMATION

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Common Stock Exchange Listing
New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at
December 31, 2004: 118,927,444

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Annual Meeting of Shareholders

The Annual Meeting of Shareholders will be held at 2 p.m. CDT in the La Salle "A" Room of the Doubletree Hotel, 400 Dallas Street, Houston, Texas 77002 on Tuesday, May 3, 2005. Information with respect to this meeting is contained in the Proxy Statement sent with this Annual Report to holders of record of EOG Resources, Inc. Common Stock. The Annual Report is not to be considered a part of the proxy soliciting material.

Additional Information

Additional copies of the Annual Report and the Form 10-K are available upon request by calling (877) 363-EOGR or through the EOG Resources website at www.eogresources.com. Quarterly earnings press release information and SEC filings also can be accessed through the website.

Financial analysts and investors who need additional information should visit the EOG website, www.eogresources.com, or contact Investor Relations at (713) 651-7000.

OUR EMPLOYEES Latiff Abdool Harold Abernathy Ismael Abila Linda Abrego Rosie Abrego Maria Acevedo Linda Acosta Tammy Adair Kimberly Adams Ronnie Adams Michael Adrion Candelario Aguilar Amit Ahuja Roberto Alaniz Melissa Albert William Albrecht Patricia Aleman Joseph Alexander Gabriella Aliberti-Mabry Raymond Allbee Kenneth Allemand Kenneth Allen Cathy Anderson David Anderson Joseph Anderson William Anderson Francisca Andreassen Hilary Andrews Tammy Andrews Jim Anschutz Barbara Anselm Andres Arambula Kerry Archibald Blaine Ardelian Rene Argueta Erick Armentrout Ralph Armentrout Donald Armstrong Robert Armstrong Derek Arnold Lance Arnold Paul Arnott James Ary Terry Avery Balliram Bachan Peter Bacon Lanny Baker Twila Baker Maire Baldwin Jerry Ball John Ball F. Blaine Balmer Jimmy Banks Valeria Banks Bijay Banthia Brian Baptiste Judy Barlow James Barnes Kelley Barnett Emilio Barrera Anthony Barrett Jennifer Barter Curt Bateman Dale Bawol Ana Beasley Michelle Beauchamp Jennifer Beavers Carla Beck Gary Beck John Becker Stephen Bedell Barbara Belcher Heather Bell Olynda Bello Adriana Benavides Steven Bennett Stephen Benoit Roy Benteau A. John Bergquist Martha Bernardini Kerry Bernas Timothy Berry Berwin Best Sandeep Bhakhri Jerry Biggs Jeffery Birkelbach Blaine Bischoff Wendy Bjorkman Sidney Bjorlie Jennifer Blackburn Randolph Blackburn Brad Blackwood Carolyn Bladek Dana Blevins Teresa Block Stanley Blundell Kenneth Boedeker Susan Boedeker Mark Boehm David Boerm Timothy Boggess David Boisjolie Kimberly Bolton Wendy Bone Kelly Bonogofski Alisa Booth Vera Boren Richard Bosch Stewart Bosch James Bouillion Deidra Bourland David Bowdle Jamie Bowman Ben Boyd John Boyd Mary Bradford Diane Bradley Tom Bradley Sharleen Brand Bryan Brandon Laurie Brandon Crystal Branham Cheryl Brashear Larry Brazile Sheila Bremer Isabelle Briand Mike Brietzke Susan Bright Ann Brindle Gary Britt Rachel Britt Sonia Brittain Michael Brooks Burt Broussard Jeff Brown Jody Brown Robert Brown Steve Brown David Brunette Linda Bruster Alecia Bryson Steven Bryson James Bucci Shane Buck Kerry Burdett Geoff Burkart Rick Burke Wesley Burke Wendy Burlock James Burnett John Burnette Tina Burns Laurie Burt Paul Burt Debbie Butler Dustin Bynum Kenneth Byrd William Byrd Kim Cadena Shardee Caesar Brad Cage Robert Cahill Gary Cain Mark Cain Victoria Calhoun Carol Cameron Howard Cameron Carleen Campbell Catherine Campbell Daniel Canales David Canales Charlotte Candler Joseph Cantu Emmett Capt Joseph Caputo John Cardin Santos Cardona Charleen Carlos Skipper Carnes Ronald Carney Stacy Carpenter Jacqueline Carr-Brown Noemi Carrillo Leland Carroll Ricky Carroll Robert Carroll Gary Carson Kenneth Carter Gary Cartwright Susan Carulli Nanci Cassard Jesus Castillo Dennis Cates Paula Chaffin Rinu Chahal Katherine Chalfant Sheryl Champagne Shelly Chan Lewis Chandler John Chapman William Chapman Andres Chavez Linda Chenoweth Clara Chiew Helen Chin Michael Chong Tracey Chong-Ashing Penny Chrisman Lorne Christal Beverly Christensen Elnora Christoffersen Douglas Chrumka Samie Clanton Chantelle Clark Douglas Clark John Clark Richard Clark Sandra Clark Julie Clay Tamara Clayton Eugene Clower Linda Cluiss April Colbert Ruby Cole Carolyn Coleman Clifton Coleman James Coleman Steven Coleman Robert Coles Gerald Colley Charles Colson Christian Combs Traci Conner Paul Connolly Erica Conroy Barry Constable Duane Cook Karen Cook Michael Cooksey Tyler Coon Lisa Copeland Craig Cormany Neal Cormier Roy Coston Stephen Couch David Covill Betty Cowart Emily Cowen Kim Cowherd Dawn Marie Cox Mark Cox Russell Cox Jack Cozart Hal Crabb Logan Craig Alicia Craigwell Douglas Cramer Garth Cramer Bette Cranford John Cranmore Nora Crawford Sherry Crawford Wayland Crawley Misti Creach Robert Crim Paul Cross Barry Crowder Phyllis Croy Stephen Croy Herminia Cruz Terry Csere Wade Cuch Valerie Culpepper Ferdinand Cumberbatch James Cunkelman Peter Cunningham Nancy Currie Louis D'Abadie Diana Dabiedeen Ashish Dabral Jeff Dahl Lee Dailey Donald Daisher Wendy Dalton Fassil Daniel Robert Daniels Marsha Danzel Leandro Daponte Judy Dargin Roger Dart Bryan David David Davis Donald Davis Randall Davis Robert Davis William Davis Jeremy Dawson Richard Day David Deal Teresa Dean Patricia Dechow Howard Deis Elizabeth DeLaGarza Chris Delcambre Gloria DelCampo James DelCampo Joseph DelCampo Tonie DeLeon Brenda Dellinger Phil DeLozier Marie Deslattes Ronald Devoll Shahin Dewji Nancy Diaz Curtis Dill Trudy Dillon-Patrick John Dixon Kurt Doerr Daniel Domingue Holly Dominguez Manuel Dominguez Kathryn Donaldson Daryl Doodnath Timothy Dort Rebecca Doyle Patrick Draves Timothy Driggers Bobby Driver Barbara Drosche Hans Dube Denis Dufresne Cynthia Duge James Dunford Lane Dunham Kenneth Dunn George Dupre Brian Durman Frederick Ealand Louise Earl Karen Ebbert Madeline Edgley Patricia Edwards Ronald Einerson Cynthia Einkauf Jerome Ellard Mark Ellerbe Terrence Elliot Edward Elliott Robert Ellis Donna Ellsworth John Ellyson William Elmer Jerome Elmlinger Ronald Ensminger Darrah Eresman Karen Erwin Marc Eschenburg Amanda Espinosa Don Estill Sandra Estrada Betty Evans Carol Evans-Danver Kathleen Fabra Clyde Faggett Roger Falk Richard Fansher Carol Faullon Melanie Fehr Lawrence Fenwick William Fergeson Len Ferguson Richard Ferguson Olga Ferrell John Ferringer Perry Fields Marilyn Fish David Fleming James Fletcher Criselda Flores Daniel Flores Robbye Floyd-Archibald Clifford Fobes Richard Fobes James Folcik Grace Ford Larry Formo Susan Forsyth Chantal Fortin Mark Fortuna Darryl Fossen Therese Foster Ilona Fournier Larry Fournier John Fowler Lonnie Fox Charles Francis Janie Franco Lydia Franco Christine Frank Danny Frederick Joe Freeman Reginald Freestone Judy Frey William Fricker Bonita Friesenhahn Kari Fritz David Frye Laura Fuentes Catherine Gage Jeremy Galeski Raymond Galvan Barbara Ganong Stephen Garber Agustin Garcia Maria Garcia Vic Garcia Kaylene Gardner Michael Gardner Dwayne Garnett Robert Garrison Yolanda Garza Richard Gauthier Debra Gay Marshall Gazette Maria Geerligs Zola George James Gerlinger Mark Germinario Karen Gibson Owen Gibson Jeff Gigstad Murray Gilhooly Victor Gilliam Melissa Gillispie Michael Goad Frank Gomez Jose Gonzalez Rosa Gonzalez Jeffrey Gordon Casey Gordy Linda Goroniuk Mark Gorski Lisa Gosine-Alleyne Lindsay Gowan Vickie Graham Patricia Granger Doris Grau Dortha Gray Katherine Gray Eldon Greanya Jayne Green Rickey Green Ruth Green Norma Greenlee James Gregory Julie Grey Wendi Grieve Dana Griffin Mary Grisaffi Larry Gross Nicholas Groves Joseph Guerrero John Guillot Michelle Gummelt Emelia Guzman Laura Guzman Lula Hain Kent Hale Leta Hale Vivi Ann Hall Robert Halverson Phillip Hampton Debbra Hamre Susan Hanselman Andrew Hanson Kevin Hanzel Ricky Hardaway Jeffery Harmon Robert Harp Jamie Harris Joe Harris Kristina Harris Steven Harrison Burton Hartley Lance Hartwell Tracy Hartzog John Haskins Mark Hately James Hatfield Tammy Hatfield Michele Hatz Gina Hauck Debbie Haugen Darcy Hawkins Gordon Haycraft Susan Haynes Indira Heeralal Roy Hefley Michael Heil Lloyd Helms Jennifer Henderson Ronald Henderson Bryan Hendricks Bryan Hennigan Carla Henry Dan Henry James Henry Richard Henry Bernadette Hernandez Eduardo Hernandez Irene Herrera Stephen Hertig Billy Hester Tom Heydt Deborah Hibler Vicki Hietpas John Hill Elise Hillman Stephen Himes Linda Hoagland Randy Hodgins James Hodgson Garett Hodne Chris Hoefer Deanna Hoffman Myron Hoffman Danny Holgate Wayne Holt Tyler Homan Helen Hosein-Mulloon Glenn Howard Stephen Howell Adriana Howells William Howells Andrew Hoyle Donna Hradil Robert Hubbert Frank Hudec John Hudec Brandy Hudson Carolyn Hughes Deanne Hulquist Wan-Hsiang Hung Barry Hunsaker D'Undra Hunter Michael Huntington Timothy Hutchins Raymond Ingle Greg Ingram Kathleen Insley Michael Isaacs Elizabeth Ivers Diana Jablonski Herschel Jackson Kenneth Jackson Melinda Jackson Ronnie Jackson Camille Jacobs George James Ann Janssen Darryl Janssen Lonnie Jeannerett Donna Jenkins Lee Jenkins Donna Jensen M. Teresa Jimenez Craig Jobe Bruce Johnson Corby Johnson Courtney Johnson Deborah Johnson Donna Johnson Janet Johnson Joyce Johnson Sonya Johnson John Johnston Patricia Johnston Vickie Jolley Amy Jones Calvert Jones Dennis Jones Gregg Jones Linda Jones Matthew Jones Sherry Jones Douglas Jordan Jon Jorgenson Sheryl Joubert James Joyce Sheri Jurecek Astrid Kalmet Teresa Kaplan Terrence Karka Olaf Karlsen Srinivasulu Karnati Steven Keenan Thomas Keetley Theodore Kelly Howard Kemp Wilbur Kennedy James Kerbow Sara Kerley Eldon Keung Mphatso Khoza Robert Kidney Richard King Rick King Colin Kinniburgh Carol Kirksey Timothy Kirksey Tracy Kisell Denise Klatt Derek Klein Mildred Kleinschmidt Ronald Knippa David Kocian Anthony Koester Saul Korrodi Joseph Kozeal Nancy Krahn Lynn Krailo Mark Kraus Lisa Krawchuk Ronald Krieger Anthony Krupa Darcy Kubik Albert Kucharski Shrut Kumar Charles Kunze Sharon Kurzy Kenneth Kuykendall Cyril Lackey Nancy Lackey Ernest LaFlure Jason LaGrega Renee Lagrone Kwong Yip Lai Gordon Lain Cori Lambert George Lambert Jeffery Landrum Randy Landrum Joseph Landry John Lang Richard Lanning Janice Laughery Bill Laughlin Joan Laury Peggy Lavine Felicia Lawal Jill Lawhon Renee Lawrence Herman Lawson Lugard Layne Kim-Hue Le Michael LeBaron William Leflar Shelley Leggitt Tommy Lehman Loren Leiker Philip Leimer Charles Lemon Kevin Leonce Brent Lesy Herman Leung Randolph Lewellen Clara Lewis Gareth Lewis Neil Lewis Allen Light James Ligon Helen Lim Warren Lindland Stephen Lipari Scott Listiak Elaine Lloyd Karen Lockhart Milford Lockwood Curtis Lodhar David Long Robert Long Mark Longden Lindell Looger David Looney Annel Lopez Ernest Lopez Jerome Lopez Juan Lopez Jonathan Loreco Douglas Love Robert Love Gloria Loveless Allen Luckow Jeanene Lueckemeyer Damian Lynch Clarissia Lynn Jocelyn Lyrock Mary Maestas Darryl Magnusson Charles Mallary Marla Mallett-Davis Davina Manohar Preston Mansor Donald Manton Tony Maranto Kenneth Marbach Mara Marchesan Colleen Marples Heather Marshall Jacob Marshall Claudia Martens Debra Martin Patricia Martin Rebecca Martin Thelma Martin Antonio Martinez Sergio Martinez Kelly Mason John Massie Cathy Mathias Mark Mathias Beverly Matthews Mervin Matus David May Jeffrey May Michelle Mayo Vicki McAteer Robert McAuley Naomi McBeath Ronald McBee George McBride Marilyn McCall Christopher McCarthy Ricky McCaslin Kenn McComb Michael McCown Thomas McCray Daniel McCright Karen McDaniel Terri McDearman John McDonald Richard McGough Jay McIntyre Kenneth McKinley James McKinney Beverly McMahan Tolliver McNeill Megan McWhorter Linda Meade David Meadows John Mears Joseph Meeks John Melby David Men Marilyn Merryweather David Metzner Gail Meyer Rachel Meyer Tina Meyer Eloise Meza Greer Mick Kenneth Middlemiss Rudy Mikulec Jill Miller Matthew Miller Toni Miller Robert Milne David Minions Sheila Mirich Karen Mitchell Chris Moffat Terence Mok Lisa Molinar Steven Molitor Anthony Monariti Steven Montez Delores Montoya Judith Montoya Aramis Morales Gerson Morales Ronald Morgan William Morgan Douglas Morgareidge Andrew Morris William Morris Kristin Morton Richard Morton Michael Moton Pat Moya Douglas Mueller Arthur Mullenax Michael Mullins Edward Mumford Alonzo Munoz Linda Munoz Robert Munoz Thomas Murphy Patrick Murtagh Daniel Murton Ramey Musgrave Christopher Myers Amanda Naaykens Harrienarine Nanan Shareen Nash Corina Neagu Heather Nealson Daniel Needham Todd Neely Brian Neemar Barbara Nelligan Jimmy Nelson Shona Ness Adrian Neumann Kevin Newberry John Nicholas Judy Nichols Mark Nicholson Thomas Nielsen Richard Nies Juan Nieto Orrison Niles Xiaomei Ning Sherly Nissing Benjamin Nolan Joel Noronha Murray Novak Lori Nugent Timothy Nugent Janie Null Terry Nunn Martha Nutter Claude Oberholzer Alison Oblinger Kolton Obritsch Lori Odom John O'Donnell Julie Ogren Michelle Oliver Daniel Olson Peter O'Mara David O'Neill Carmen Oney D. Alexander Orr Jay Orr Richard Ott Jacky Ouin Ray Owsley Andrew Pakes Debra Palmer Douglas Palmer John Palmer Mike Palmquist Elizabeth Panfely Mark Papa Tracy Pape Kevin Parker Wendy Parker Theodore Parrish Curtis Parsons Michael Partin Antony Passaro Barbara Paul William Pauly Brenda Payne Debrah Payne Brent Pears Annette Pearsall Richard Pedder Paul Pendleton Katherine Perez Kim Perez Stacy Perez Sandra Perko Narine Persad Vanessa Pete Joseph Peter Donald Peters James Peterson Russell Petry Timothy Petta James Pettibone Kevin Pfister Dorothy Pflughaupt Georgia Phillips Sammy Pickering Silvestre Pineda Karen Pitman Lisa Pittman Donald Pitts Darcy Poncsak Batina Poorbaugh Kyla Porche Earnest Powell Virginia Powers Donald Presenkowski Debbie Price Susan Price Ralph Proksell Peter Pumilia James Pusley Michael Quinn Shelley Quiring Shawn Racca Marjorie Rael Elizabeth Ramirez Rodolfo Ramirez Ann Ramlochan Gregory Ramsey Keith Rasmussen Rance Rasmussen Stanley Rauh David Rawlins Jimmy Redfearn Gilberda Reed Cheryl Reese Anna Reeves Kathleen Reeves Derek Reiber Kelly Reiber Brandi Reiling Terry Rekdal Colleen Remenda Fred Rhodes Richard Rhodes Ronald Richard Clarence Ries Jerry Rietveld Cris Riley Jeffrey Risinger Earl Ritchie Roy Roach Wilbur Roane Marvin Roark Clifford Roberts Rita Robicheaux Bettie Robinson Carl Robinson Lynita Robinson Samuel Robinson Kaye Rockel Elitha Rocke-Maharaj Jeanne Rodgers Debra Rodieck David Rolando Linda Romano Cindi Rosenau Vicki Ross Tara Rosser Sarah Rotermann Patricia Roufs Bridget Row Kelly Roy Kenneth Roy Kristie-Anne Royal Stephen Ruiz Douglas Runkel Karen Rushforth Jeanette Rutherford Paul Sacco David Saldivar Ellen Saldivar Ivan Salick Gina Salinas Linda Samford David Sammons Inocente Sanchez Bobby Sanders Danny Sandifer Marikay Saranthus Edgar Sarmiento Roderick Sauter James Schaefer Brenda Schamehorn Rick Schatz Wendi Scheier Darla Schmaltz Jerry Schmaltz Jamie Schmid Brian Schmidt Gerald Schneider Shane Schneider Keith Schnurer Shaun Schnurer Curtis Schoenfeld Margaret Schroeder Helen Schroller Leann Schroller Paul Schuler Bobby Schultz Frederick Schultz Alfreda Schulz Charles Schwab Michael Schween Kim Schwoerke Dolores Scotka Andrew Scott Marion Sczykutowicz Urban Seay Edmund Segner Brian Sehn Mel Sehn Timothy Seiple Markie Senn Hector Serna Roxana Serpa Bodee Sessions Larry Seymour Gregory Shaffer Pamela Shaffer Eneta Sharma Douglass Sharp Alison Sharratt Donald Shaw John Sheehan Donald Shelden Ted Shell Sidney Shepperd Tracy Shipp Dale Short Michael Sickon Jacqueline Sides Daryl Siebens Teena Simmons Ria Singh-Date Sallie Singleton Trent Skelton Robert Slavens Gary Slusher Joseph Smathers Linda Smedlund Ace Smith Charles Smith Delmer Smith Gary Smith Heather Smith Kevin Smith Paula Smith Robert Smith Shawn Smith Sheila Smith Thomas Smith Cheryle Snow Janie Snyder Katherine Sohns Larry Solomon Billie Sowle Anslem Spears Debra Spears William Speer Jeff Spencer John Spradley Stephanie Spriggins Terrie Springman Alan Stacy Manuel Staffero Jack Staley Randall Stanger Bridgett Staples Morgan Steele Patti Steely Walter Stefanik Verna Stein Brenda Stephens Robert Sterling Martha Sterner Carrie Stevens Phillip Stevens Rodney Steward Carly Stewart Kent Stewart Kenneth Stillman Jerry Stinson Rex Stout Scott Stovin Hugh Stowe Cindy Stowell Jeffrey Strausser Elton Street John Studt Jason Sugg Suvarna Sule Gary Superville David Swauger David Sweeley Richard Swimm Sundai Swinney James Szenasy Valarie Taber Dara Tatum Deborah Taylor Edward Taylor Heidi Taylor Jeane Taylor Kenneth Taylor Nick Taylor Ralph Telford James Terando Eileen Thoede Gary Thomas J. Layton Thomas Kimberly Thomas Melva Thomas Rita Thomas William Thomas James Thompson Robert Thompson Mark Thorne Christina Thring Dewayne Tidwell Joseph Tigner Gina Tobey Brent Tocher Brian Tompkins Kelly Tompkins Ola Tompkins Patrick Tower Dominico Tran Jennifer Tran Linda Tran Tuongvan Tran Steven Travis Marcus Trevino David Trice Jonell Trodlier Delbert Trolinder John Troschinetz Joseph Troupe Bella Trudel Linda Tucker Dan Tuer Valerie Tuitt Cameron Turnbull Linda Turner Sonja Turner Lawrence Tuttle Zane Tymrick Tull Umphres Sherry Upton Andrea Urciuoli Vance Utri David Vague Brian Valencia Michael VanHorn Cynthia VanRanken Michael Vargo Martha Varice Terry Vaughn Evelyn Vauthier Jennifer Vega Emiliano Vela Mark Verhoeve George Vieira Cheryl Vierling Timothy Vogler Andrew Volk Prody Vong Bruce Voshall George Vouronikas Denise Wade Dallas Wagner Frederic Wagner Dennis Wagstaff Roger Wainwright Deborah Wakeford Matthew Walden Paula Waldo Julie Walker Wanda Walls Joseph Walthall Deborah Walther Cynthia Walton Martin Wang Allan Wanner Ralph Warby Laura Wardlaw William Wardlaw Freddie Warren Andrew Washburn Alan Watkins Karon Watson Steven Weatherl Robert Weeks Kenneth Weiland Tyson Weinberger Amanda Weishuhn Michael Welch William Weldon Katherine Wells Nathan Wells Ronald Wells Steven Wentworth Jeffrey Wenz Kari Wenz Robert West Davette Weston Erica Westphalen James Whaley George Wheat Leesa White Michael White Stephen White Alison Whiteley Melanie Whitlock Donald Whitmer Richard Whittingham John Wilkins Nancy Wilkins Dan Wilkirson Cheryl Williams Raymond Williams Steven Williams Rachelle Willis Alicia Wilson Daniel Wilson Danny Wilson Frank Wilson James Wilson James Wilson Leila Wilson Robert Wilson Thomas Wilson Walter Wilson William Winkelman Sharron Winter Anna Wojtowicz Barbara Wood Pat Woods David Work Lloyd Woychuk David Wright David Wright Angela Wysocki Theresa Wysocki Michael Ybarra Angie Young Craig Young Qian Yu Jeffrey Zawila Craig Zempel Barry Zinz

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