eog resources

2000 ANNUAL REPORT TO SHAREHOLDERS

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1st Quarter	2nd Quarter	3rd Quarter	4th Quarter

Financial and Operating Highlights

(In millions, except per share data, unless otherwise indicated)	**2000**	1999	1998	1997	1996	1995
Net Operating Revenues, As Adjusted *	**$ 1,490**	$ 794	$ 732	$ 784	$ 747	$ 667
Income Before Interest and Taxes, As Adjusted *	**$ 695**	$ 147	$ 81	$ 183	$ 204	$ 195
Net Income Available to Common, As Adjusted *	**$ 386**	$ 58	$ 43	$ 117	$ 140	$ 141
Adjustments for India and China Operations and Certain Non-recurring Items	**$ -**	$ 511	$ 13	$ 5	$ -	$ 1
Net Income Available to Common, As Reported	**$ 386**	$ 569	$ 56	$ 122	$ 140	$ 142
Discretionary Cash Flow Available to Common *	**$ 1,007**	$ 466	$ 427	$ 492	$ 478	$ 421
Exploration and Development Expenditures *	**$ 687**	$ 428	$ 716	$ 619	$ 515	$ 492
Wellhead Statistics						
Natural Gas Volumes (MMcf/d) *	**908**	892	915	871	830	743
Natural Gas Prices ($/Mcf) *	**$ 3.49**	$ 2.01	$ 1.80	$ 2.11	$ 1.84	$ 1.36
Crude Oil and Condensate Volumes (MBbls/d) *	**27.5**	19.4	19.6	17.6	16.8	16.6
Crude Oil and Condensate Prices ($/Bbl) *	**$ 29.57**	$ 18.02	$ 12.65	$ 19.24	$ 20.70	$ 16.80
Natural Gas Liquids Volumes (MBbls/d)	**4.7**	3.4	3.9	3.9	2.5	1.4
Natural Gas Liquids Prices ($/Bbl)	**$ 19.87**	$ 12.24	$ 8.38	$ 12.17	$ 13.00	$ 11.31
NYSE Price Range ($/Share)						
High	**$ 56.69**	$ 25.38	$ 24.50	$ 27.00	$ 30.63	$ 25.38
Low	**$ 13.69**	$ 14.38	$ 11.75	$ 17.50	$ 22.38	$ 17.13
Close	**$ 54.63**	$ 17.56	$ 17.25	$ 21.19	$ 25.25	$ 24.00
Cash Dividends Per Share	**$ .135**	$ .120	$ .120	$ .120	$ .120	$ .120
Average Shares Outstanding	**117.1**	140.9	154.3	157.4	159.9	159.9
Year-end Shares Outstanding	**116.9**	119.1	153.7	155.1	159.8	159.8

* 1995 - 1999 adjusted to exclude India and China operations and certain non-recurring items.

On the Cover

EOG salutes its employees who are building the exploration and production company of the future. EOG's stock price more than tripled during 2000, ranking third in Standard & Poor's 500 index.

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The Company

EOG Resources, Inc. (EOG) is one of the largest independent (non-integrated) oil and gas companies in the United States. It is engaged in the exploration and development, production and marketing of natural gas and crude oil primarily in major producing basins in the United States, as well as in Canada, Trinidad and selected other international areas.

At December 31, 2000, EOG's estimated net proved natural gas reserves were 3,381 Bcf and estimated net proved crude oil, condensate and natural gas liquids reserves were 73 million barrels. Approximately 56 percent of EOG's reserves on a natural gas equivalent basis were located in the United States, 15 percent in Canada and 29 percent in Trinidad. At year-end 2000, EOG had approximately 850 employees.

2000 Highlights

EOG reported record net income available to common of $385.9 million or $3.30 per share. This compares to 1999 results of net income available to common of $57.6 million, or $.49 per share, adjusted to exclude operations in India and China transferred to Enron Corp., and various non-recurring items primarily associated with the share exchange agreement with Enron Corp.

On a per share basis, compared to as-adjusted 1999, total company production increased 8.9 percent, natural gas production increased 3.6 percent, crude oil production increased 43.5 percent and natural gas liquids production increased 40.6 percent.

EOG exceeded its original absolute production goal of 4 percent in North America by increasing production over 8 percent, primarily through the drillbit, compared to 1999.

The after-tax rate of return on EOG's 2000 capital program in North America was 46 percent, which breaks into a 16 percent rate of return on the $102 million spent on property acquisitions and a 66 percent rate of return on the $541 million spent on land, seismic and drilling.

EOG repurchased a total of 2.2 million shares of common stock, reducing the share count from 119.1 million at year-end 1999 to 116.9 million at year-end 2000. To offset employee stock option exercises, an additional 6.7 million shares also were repurchased.

During the second quarter 2000, EOG increased the annual common stock dividend from $.12 per share to $.14 per share. During the first quarter 2001, the common stock dividend was increased by another $.02 per share to $.16 per share.

EOG paid down $131.3 million of debt reducing the debt-to-total capitalization ratio from 47 percent at year-end 1999 to 38 percent at year-end 2000.

Total EOG proved reserves increased by approximately 6 percent to 3,821 Bcfe at year-end 2000.

EOG replaced 152 percent of production from all sources at a finding cost of $1.07 per Mcfe.

EOG's stock appreciated 211 percent, reflecting the company's leverage to North America natural gas. EOG was the third best performer in Standard & Poor's 500 Index in 2000.

EOG set up its North America operations for future growth by adding significant acreage in several new geologic trends and increasing its experienced geological and geophysical employee headcount by over 25 percent to enhance future exploration growth. EOG also created a new onshore operating division to establish a foothold in the Appalachian Basin.

Internationally, EOG signed a contract to supply 60 MMcf/d of natural gas from the U(a) block to serve an ammonia plant in Trinidad.

EOG was the second most active driller in the U.S. in 2000 measured by footage drilled, and plans to maintain its active drilling program in 2001.

A Year of Continued Momentum

AT THE START OF 2000, EOG WAS CONFIDENT IN THE VALIDITY OF ITS LONG-TERM NATURAL GAS THESIS AND STRATEGY. AS ENERGY EVENTS UNFOLDED DURING THE YEAR, EOG'S TENACITY AND SINGLE-MINDED PURSUIT OF THE FUNDAMENTALS WERE REWARDED. ITS 2000 STOCK PRICE PERFORMANCE WAS UNPARALLELED IN THE INDUSTRY, ITS ORGANIC GROWTH WAS UNMATCHED AND ITS POSITIONING FOR CONTINUED SUCCESS IN 2001 AND BEYOND WAS SOLIDIFIED.

Letter to Shareholders

EOG has been called a 'no-excuses' company. Our approach to the exploration and production business has been characterized as 'what you see is what you get.' Frankly, we like both descriptions. They accurately sum up EOG's commitment to a long-term natural gas strategy and the fundamentals that underpin our company's foundation. EOG is *natural gas based, per share focused*, and *rate of return driven*, and is both a *low cost producer* and a *consistent performer.* Our commitment to that strategy and adherence to those fundamentals has not changed.

In our first full year as a truly independent exploration and production company (no longer associated with Enron Corp.), we made progress toward our goal of being ranked as the best independent exploration and production company in the industry. Our success created a momentum that was fueled by achieving — and in some cases exceeding — the goals we articulated this time last year. We also benefited from the highest natural gas and crude oil prices in recent history. Therefore, we are reporting outstanding 2000 results.

Delivering on our promises

EOG's stock price appreciated 211 percent during the year, ranking it third in the S&P 500 Index, to which we were added in November. EOG outperformed every stock in our peer group, more than doubling their average stock price appreciation. For 2000, EOG reported net income available to common of $385.9 million, or $3.30 per share, compared to 1999 net income available to common of $57.6 million or $ .49 per share, adjusted to exclude operations in India and China transferred to Enron Corp., and various non-recurring items primarily associated with the share exchange agreement with Enron Corp.

With one of the highest weightings to natural gas in the industry, EOG decided early in 2000 to remain unhedged. This proved beneficial when industry natural gas prices began a steady rise from $2.29 per MMbtu on January 1 to $9.52 per MMbtu on December 31, resulting in over $1.0 billion of discretionary cash flow to EOG. Natural gas prices for the year averaged $4.29 per MMbtu. Much of that cash flow was plowed back into the ground allowing us to substantially increase our production through the drillbit in 2000 and to build a drilling

Left, Mark G. Papa

Right, Edmund P. Segner, III

inventory for the future. Other cash above our capital program was used to repurchase shares and reduce debt.

During the year, we also took advantage of industry merger dynamics to make a significant investment in geologists and geophysicists, increasing EOG's headcount of prospect generators by 25 percent.

At the beginning of the year, EOG set a target of 4 percent growth in North American production, increased it to 7 percent at the end of the first quarter and upped it to 8 percent at the end of the third quarter. This degree of organic production growth is unique in the industry and is particularly important at a time when North American natural gas has become so valuable.

Because of EOG's atypical focus on earnings per share, cash flow per share and production per share, the reduction of over two million shares of common stock outstanding during the year was significant. We closed out 2000 with 116.9 million shares of stock outstanding, continuing the pattern we established when EOG began to reduce the 160 million shares it had outstanding in 1996. During 2000, we paid down over $130 million of debt, ending the year with a 38 percent debt-to-total capital ratio. We also announced a 17 percent increase in our annual dividend from $.12 to $.14 per share in the second quarter.

Each of our seven North American Divisions and our International Division delivered outstanding performances in 2000 with continued emphasis on reinvestment rate of return. We increased the number of divisions during the year by adding EOG Resources Appalachian LLC, following the acquisition of Somerset Oil & Gas Company, Inc. of Indiana, Pennsylvania. This addition gives us a foothold in a new, proven hydrocarbon basin.

Natural gas becomes North American headline news

During the winter of 2000-2001, tight natural gas supplies and strong demand fueled by colder than normal winter temperatures after four years of mild weather converged to push natural gas prices to new highs. This latest chapter in the North American natural gas story caught consumers by surprise. However, at EOG, we regarded this convergence as a matter of timing. These factors have combined to establish a new price benchmark for natural gas and heighten awareness and appreciation for this clean burning, efficient, environmentally friendly fuel. EOG expects continued tightness in the natural gas market. It is anticipated that the future will be shaped by the following trends:

• Demand for natural gas will continue to escalate from 22.2 Tcf this year to 29.0 Tcf in 2010 in the U.S., according to a recent National Petroleum Council study. Much of that increase will be the result of new demand from natural gas fired electric generating plants that are already being approved, sited and built. The recent California power crisis has confirmed the need for additional plants.

• During the decade of the 1990s, natural gas from individual wells was produced at a faster rate than had been historically possible due to significant improvements in completion technology. The U.S. natural gas decline rate has increased significantly over this period.

• On the supply side, U.S. reserves discovered per well dropped from an average of 1.34 Bcf in 1995-97 to .99 Bcf in 1998-99.

• Canadian natural gas supplies that have historically absorbed the majority of the growth in U.S. natural gas consumption are no longer keeping pace with U.S. demand. Western Canadian production has been flat, influenced by factors such as smaller reserve targets drilled and decline rates similar to those in the U.S.

Consistency, consistency, consistency: cornerstone of EOG's game plan

In 2001, the key to meeting our objectives is consistency. We are not a company whose strategy changes regularly — just for the sake of change.

First and foremost, *we will make prudent use of capital.* We are aware that portions of this industry have historically embarked on value-destroying capital investments, particularly in periods of high cash flow such as today. That's why we place such a strong emphasis on prudent use of capital.

We will continue to primarily explore for reserves rather than make large acquisitions. Organic growth for an exploration and production company is like blocking and tackling for a football team. It's not as glorious as being involved in a big acquisition but it gets consistent results. During 2000, the after-tax unlevered rate of return on our drilling program was 66 percent compared to 16 percent on the acquisitions we made.

Our drilling program mix now includes a greater number of larger potential prospects than in the past. This provides an augmentation to our basic 'singles and doubles' strategy.

We plan to add to our international portfolio in 2001 and will continue to increase our market presence in Trinidad. In 2000, we captured a market for a portion of our U(a) block natural gas to supply a new ammonia plant. Because of high North American natural gas prices, domestic fertilizer operations and other industries that require natural gas as feedstock are looking to alternative locations like Trinidad. We expect to add an additional market for our Trinidad gas in 2001.

We will continue to focus on activities that have a per share impact. Although EOG has not participated in a major merger, our share price has out-performed the stock price of the surviving entities of the major mergers and transactions that have taken place in the exploration and production industry peer group in the last three years.

In 2001, EOG's main thrust is to add value by generating prospects, drilling wells, controlling costs and focusing on rate of return. This strategy isn't likely to grab any headlines, but it provides consistent bottom line results.

Our strength is our employees

A review of 2000 and a look ahead at 2001 and beyond at EOG would be incomplete without paying tribute to EOG's employees. The consistent game plan that management has laid out is being put into action daily in our division offices and our Houston headquarters. Thank you for your efforts!

Welcome to all new employees, including our expanded geological, geophysical, land and engineering teams, whose expertise is adding new skills to our existing workforce of prospectors.

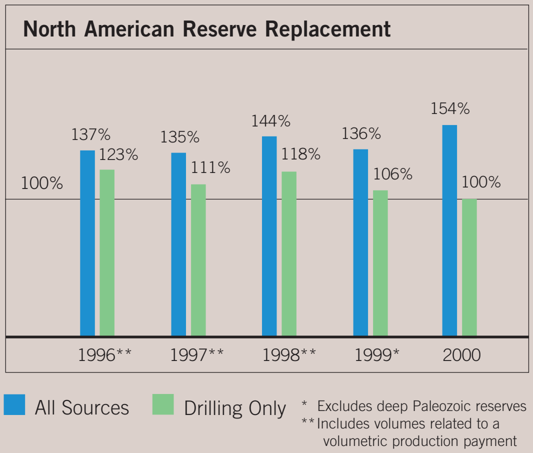
Our nine divisions operate as autonomous profit centers, similar to nine entrepreneurial mini-exploration and production companies. These decentralized, cohesive units are physically located close to their areas of operations and are focused on executing the EOG strategy. This portfolio approach to our asset base continues to deliver solid results for EOG shareholders.

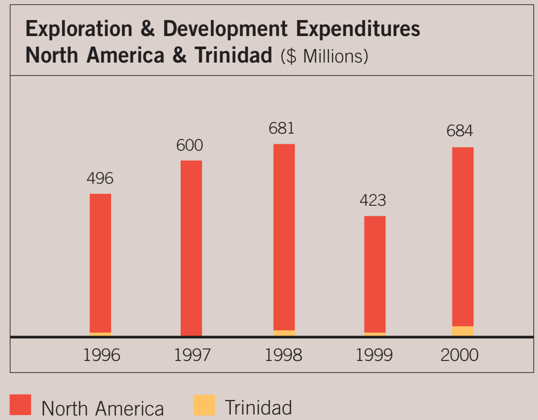
During 2000, we acted true to our beliefs at EOG and were rewarded for it. Our commitment has not wavered. There are very few management teams in the exploration and production sector who deliver long-term results. We want to continue to be one of the management teams that does. We want to be the best independent exploration and production company, the best driller and producer, and the best employer. We will settle for nothing less.

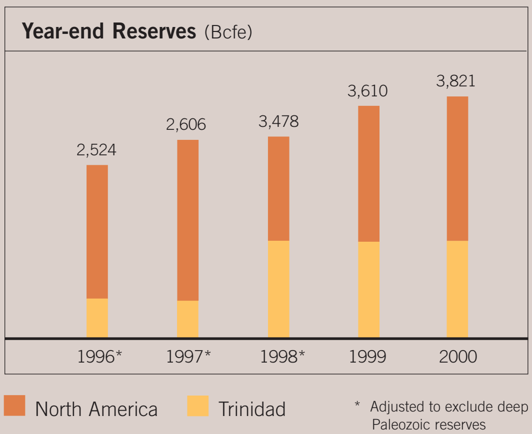
Mark G. Papa
Chairman and Chief Executive Officer

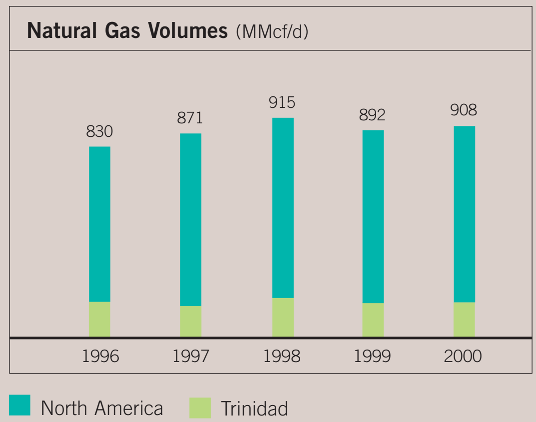
Edmund P. Segner, III
President and Chief of Staff

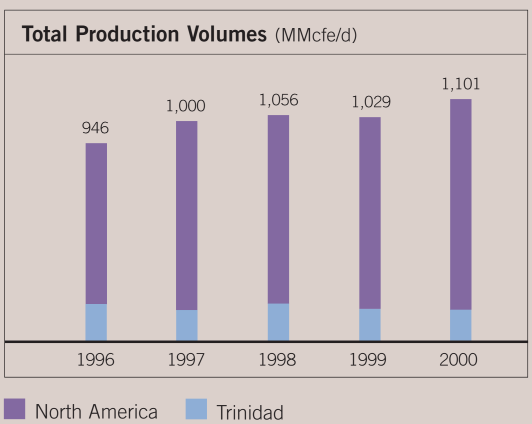
Review of Operations

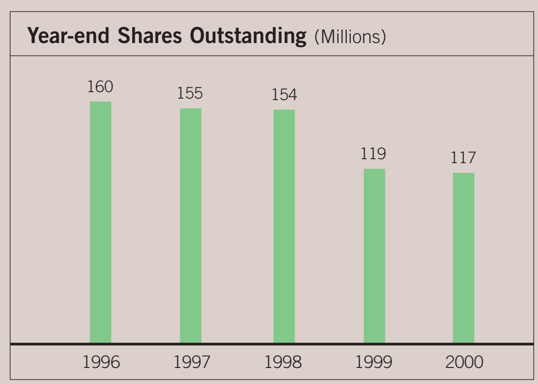


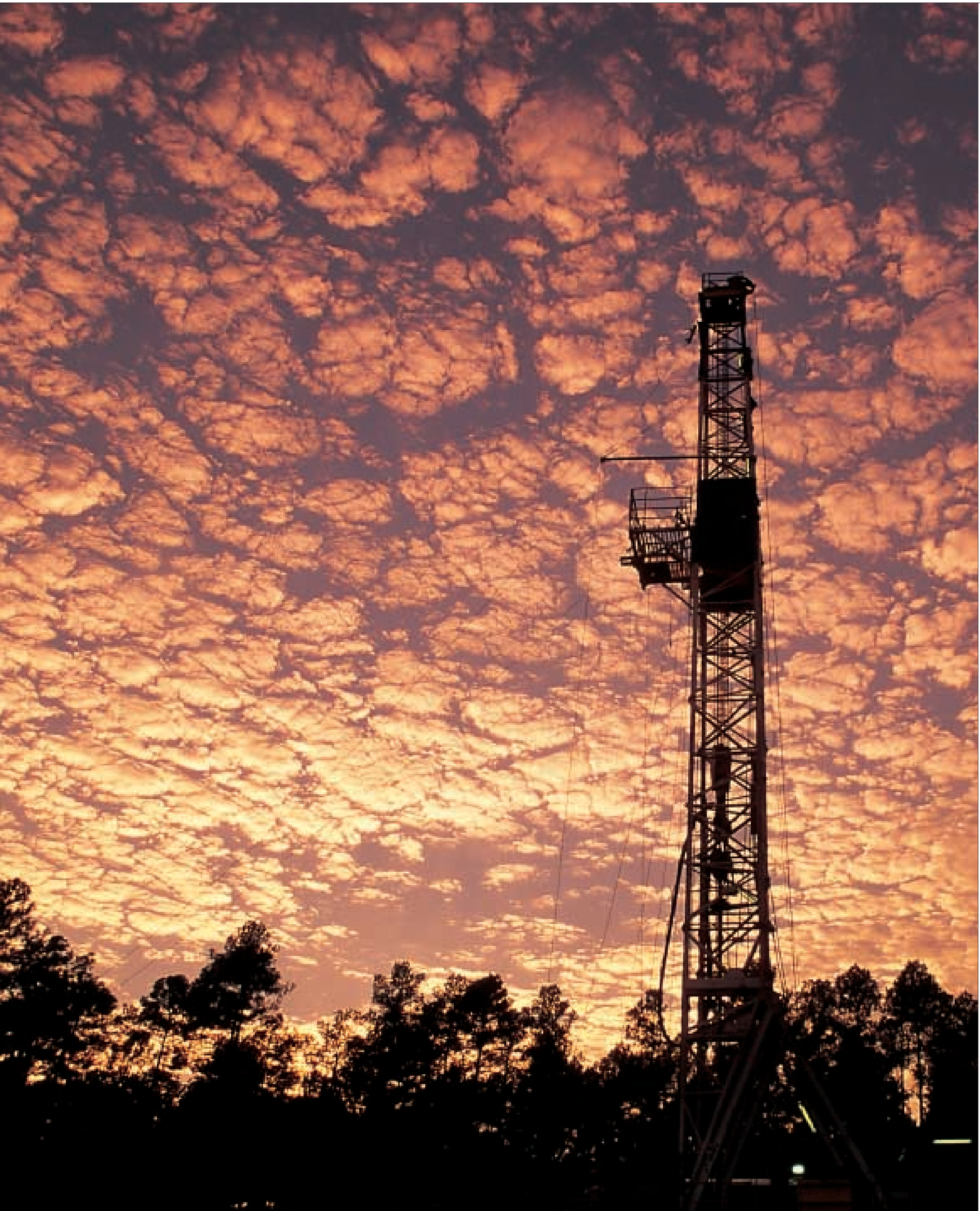












"There are enormous opportunities to add low cost reserves and production in practically every producing region in the United States. The key is the identification of these opportunities along with the ability to capture and produce the reserves. To do this, we must have the very best people, coupled with an organizational culture that allows them to perform. I believe we have the best staff in the Permian Basin and my job is to see that they have the resources and the freedom to create, acquire and produce the significant potential that exists!"
Bill Thomas, Senior Vice President & General Manager

Midland, Texas Division

"When I decided to go to work with EOG, I was immediately impressed with the quality of the core oil and gas professionals that EOG had assembled because they had a passion for finding oil and gas which equals my own."
John Troschinetz, Project Geologist

During 2000, the Midland Division generated a 100-plus percent after-tax rate of return on its total capital program and increased production 31 percent from 40.5 to 53.2 Bcfe. The division drilled 67 gross wells and was most successful in Southeast New Mexico and the Midland Basin of West Texas. Completion of a property trade with Burlington Resources Oil & Gas Company early in 2000 added approximately 170,000 acres of leasehold in the Permian Basin. By yearend, production on these properties had increased 170 percent. Three new exploration trends in the Permian Basin were defined during the year and over 200,000 acres of new leasehold and seismic options were added in these prolific areas.

In 2001, the Midland division's goal is to increase production by 10 percent. It has identified upside potential in the following trends: Morrow and Wolfcamp in Southeast New Mexico; Montoya and Devonian Horizontal in West Texas; and the Carbonate 3-D plays in the Midland Basin of West Texas. The Midland Division plans to drill over 90 wells in the Permian Basin, a 30 percent increase over its 2000 program. Plans also call for acquiring significant new leasehold and new 3-D seismic in high potential trends to set up drilling for future years. The division also will continue to add staff and grow through internally generated prospects.

Denver, Colorado Division

"EOG continues to lead the pack because its management and employees have a passion for action and a commitment to success."
Ty Stillman, Project Landman

The strategy in the Denver Division is maintaining a successful singles and doubles drilling program, while adding large exploration targets. One attractive exploration play currently underway is the North Shafter horizontal oil play near Bakersfield, California. During 2000, the division drilled 12 wells in North Shafter at a 100 percent success rate and although the play is still in an early stage of development, each successful well provides additional data and a better understanding of the area's geology. During 2001, the Denver Division plans to drill more wells in the play to continue to gather information and ultimately determine the size and potential of the oil field.

During 2000, the Denver Division integrated and merged 520 square miles of 3-D seismic data, covering the LaBarge Platform in Big Piney, Wyoming to identify and develop both shallow and deep exploratory prospects. Based on this data, EOG plans to drill more than 50 wells in the area during 2001.

Key producing areas with promising up-side potential that are part of an ongoing development/exploitation program for the Denver Division are the Big Piney – LaBarge Platform; Vernal – Chapita/Natural Buttes; California – North Shafter; and Southwest Wyoming – Cepo/Cedar Chest. Plans are to drill more than 250 wells in 2001, an 80 percent increase over 2000, and to increase production by 14 percent.

"The exploration and exploitation potential of the Western United States is enormous and EOG is in the best position to develop these resources. We have the people, acreage position, expertise and desire to succeed."
Kurt Doerr,
Vice President &
General Manager

Oklahoma City/Mid-Continent Division

"We can move faster than anybody else. Every place else I have worked they have always said that…but here at EOG…it's reality…we CAN move faster than anybody else…and that gives us a competitive advantage."
Dennis Cates, Division Operations Manager

The strategy in the Mid-Continent Division is to continue to grow by building on its success in the Oklahoma Panhandle Hugoton trend while exposing EOG to a portfolio of other significant and innovative play opportunities across the Anadarko Basin.

In the Hugoton trend, EOG has accumulated close to 1,000,000 acres through various trades, farmout agreements and leasing activity, setting up the Mid-Continent Division with a four-year prospect inventory. During 2000, the division drilled 105 gross wells in the region replacing reserves over 150 percent and generating an after-tax rate of return on total capital spent in excess of 100 percent.

The division's plans for 2001 include increasing drilling activity by 57 percent over 2000 by drilling 165 wells. These plans include 15 to 20 wells in the continued development of a new horizontal play discovered in 2000. This play is at a depth of 3,300 feet and the typical well produces from a 2,500-foot lateral at a rate of 1.2 MMcf/d and is expected to recover between 1.0 to 1.5 Bcfe. The division's plans also include testing three to five similar horizontal plays and several Deep Anadarko Basin prospects which all have significant reserve potential.

"There is absolutely no question in my mind, there are tremendous opportunities for finding significant new reserves in the mature Mid-Continent basins. Think about it…in the past three years, our division has discovered new reserves of over 180 Bcfe gross in the largest and oldest gas field in North America…Hugoton! To do this, you have to have the right people focused on the right opportunities, and then provide them with the value system and resources to be successful. It produces leaders. And being a leader is what EOG's culture, and the Mid-Continent Division's culture is all about."
Steve Coleman, Vice President & General Manager

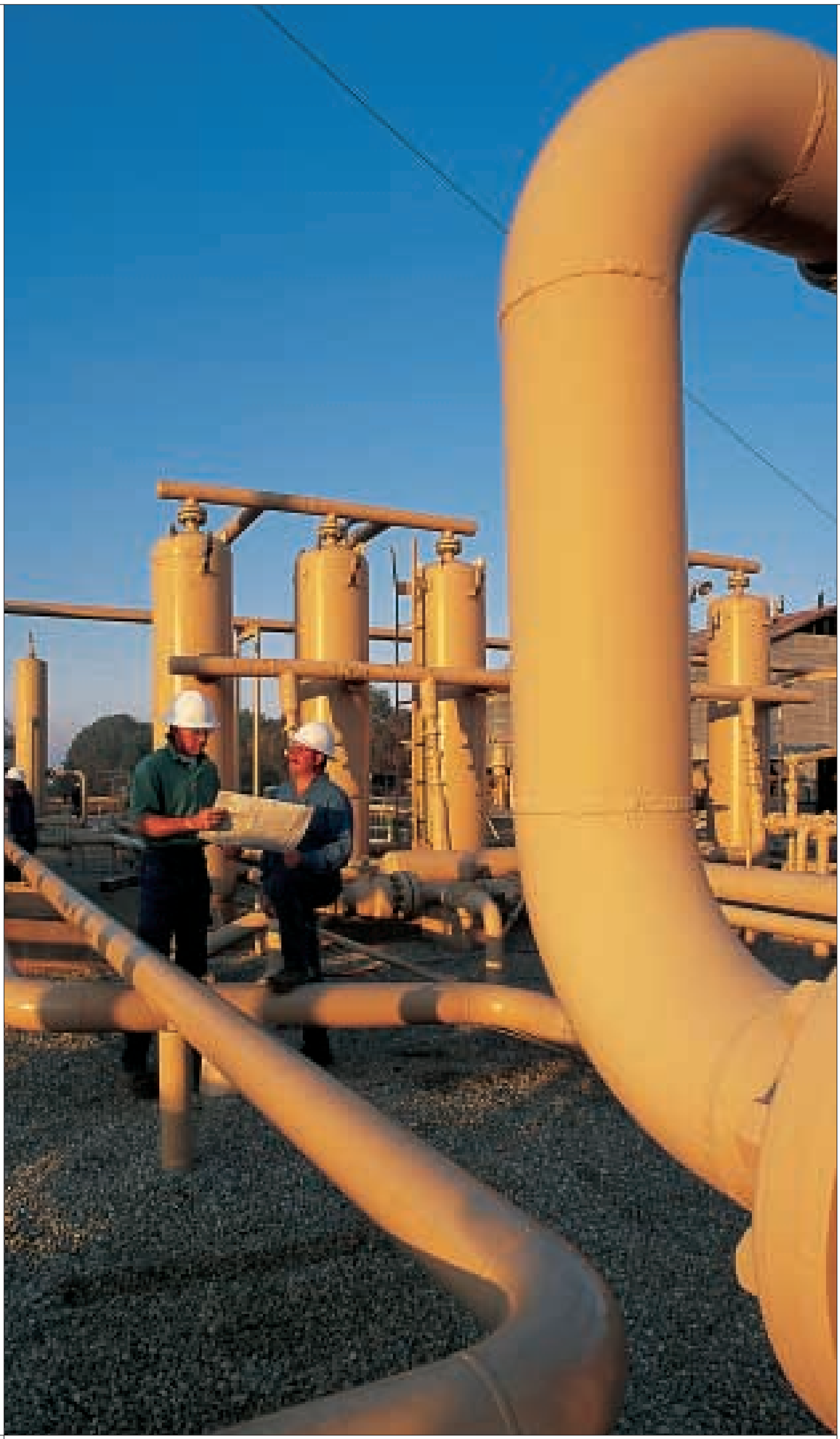
Tyler, Texas Division

"Stagnation leads to deterioration. EOG is ever changing to meet the needs of tomorrow. Status-quo is not an option."
Mark Cox, Project Drilling Engineer

The Tyler Division increased production by 35 percent to 54.4 Bcfe in 2000. Key areas of production for the division are the Sabine Uplift Region, Upper Texas Coast and Mississippi Salt Basin.

During 2000, the Tyler Division assimilated and exploited properties received from OXY USA Inc. in a property trade agreement. Through drilling success and the application of technology, the division tripled the reserve potential from original projections. EOG moved into the Bossier play and conducted a 3-D seismic survey in Galveston County, to further develop its reserve base and prospect inventory.

In 2001, EOG seeks to enter new exploratory areas including the Bossier play in Louisiana. EOG further plans to drill over 50 wells in the Sabine Uplift area.



"In the Tyler Division, our strategy is to seek the competitive edge and delegate authority and hold high expectations. We pursue only projects that the team would put its own money into. Our strategy is to maintain our production base by low cost exploitation and grow by using 3-D based exploration and purchasing exploitable assets."
Jack Huppler, Vice President & General Manager

Corpus Christi, Texas Division

"At EOG Resources, teamwork is not a corporate concept, but a method of operation. Team members are enthusiastic about meeting challenges and communicate effectively both up and down the line. The result is that team members share success. This in turn reflects the company as a whole, which celebrates success with both verbal and material recognition for its employees. After 26 years in the oil and gas business, I am surprised at how much I enjoy going to work each day."
Randall Davis, Project Landman

Early in 2000, the Corpus Christi Division made a 100 Bcfe-plus discovery in the Roleta trend of South Texas. Two to three rigs ran in the Roleta throughout the year, drilling 39 gross wells with a 90 percent success rate.

The division exceeded 100 percent reserve replacement and generated an after-tax rate of return on its total capital program that exceeded 100 percent while increasing production 21 percent to 67.6 Bcfe versus 55.7 Bcfe in 1999. The growth came from significant acreage that was added in three trends: the Lobo and Wilcox in South Texas and the Geopressured Frio along the Texas Gulf Coast. The Corpus Christi Division has identified seven fields with upside potential: Zwebb – Webb and Zapata Counties; El Huerfano – Zapata County; Pok-A-Dot – Zapata County; Tiffany – Webb County; Rosita – Duval County; Bucks Bayou North – Matagorda County; and Bay City Area – Matagorda County.

In 2001, approximately 70 gross wells will be drilled in the Corpus Christi Division, including a major extension of the successful Bay City program. Production growth is targeted at 5 percent over 2000, as well as replacement of 100 percent of production through the drillbit.

"Successful exploration starts with technically integrated teams and requires shared vision, a long term sense of purpose, new ideas, implementation and a constant focus on the bottom line. Our approach is a balance between exploration risk with the accompanying upside and an aggressive development program. We are particularly proud that all of our success in recent years is due to internally generated exploration. Our program is completely home grown."
Bob Garrison, Vice President & General Manager

Pittsburgh, Pennsylvania Division

"I've spent the first 25 years of my career in the Appalachian Basin working for independent oil and gas companies where the focus has always been on the shallow formations. I am convinced that the resources of EOG, now directed toward the development of the deeper horizons in the region, will be a successful effort for the stockholders, the company and our exploration team."
R.P. "Chip" Keddie,
Project Landman

This newest EOG division was added late in 2000 following the purchase of Somerset Oil & Gas Company, Inc., a small independent oil and gas operator in Appalachia with assets located primarily in Western Pennsylvania. The acquisition added 150 Bcf of reserves and more than 400 drilling locations to EOG's portfolio.

Historically, drilling in this region has focused on shallow wells. EOG's 2001 plan for the division is to assemble a substantial acreage position for exploration plays, shoot several miles of 2-D seismic and drill at least four exploratory wells. Plans include the drilling of at least 120 natural gas development wells in the Brady and Indiana fields in Pennsylvania. The division also will pursue strategic property acquisitions with shallow and exploratory drilling potential.

In addition, the Pittsburgh Division will focus on completing its staffing to become a fully operational exploitation and exploration unit.

"Of the hundreds of thousands of wells in the Appalachian Basin, the vast majority are less than 5,000 feet deep. Only a handful have ever been drilled deeper than 12,500 feet. Here in the shadow of Titusville, the birthplace of the American petroleum industry, we're assembling a team of intelligent, energetic and experienced people to further develop the long proven shallow gas potential and the yet unproven, but very exciting potential of the deeper producing horizons."
Gary L. Smith, Vice President & General Manager

Houston,Texas/Offshore Division

"Offshore Division employees are excited because we have found the right formula for us as a division, blending shelf and deepwater opportunities. We're evaluating them through a very disciplined approach we all believe will lead to success."
David Brunette, Land manager

EOG's Offshore Division is active in the Gulf of Mexico Shelf in Texas and Louisiana with two fields, Eugene Island 135 and Matagorda Island 623, accounting for a significant portion of the division's production. During 2000, total production was 33.3 Bcfe versus 48.6 Bcfe in 1999. On December 31, 1999, the division traded approximately 28 MMcf/d but, through successful drilling, had almost replaced this production by yearend.

During 2000, EOG drilled or participated in five wells that increased production in the division. This included an exploratory discovery at Matagorda Island 704 that added 5 MMcf/d net. EOG has a 25 percent working interest.

Taking advantage of industry mergers, EOG assembled an expert deep-water staff to initiate deep-water exploration. This team will evaluate both domestic and international opportunities to add to EOG's exploration profile.

In 2001, the Offshore Division will increase its deep-water activity by participating in one or more high impact exploratory prospects. EOG plans to maintain an active shelf exploration program by participating in eight wells. It also plans to complete a major compression project (non-operated) at Matagorda Island 623 to increase production from the field by 25 percent.

"We're maximizing our return on investment through technical and economic analysis by highly competent and motivated staff. We'll achieve growth and high profitability by implementing a mix of development drilling and high impact wildcats."
Earl J. Ritchie, Jr., Vice President & General Manager

Calgary, Canada Division

> ***"The one who says it cannot be done should never interrupt the one who is doing it!"***
> ***Sarah Rotermann, Senior Exploitation Technologist***

During 2000, the Calgary Division was again successful with its strategy of drilling a large number of shallow gas wells in Western Canada, adding production and reserves. The division increased production from 49.2 Bcfe in 1999 to 53.7 Bcfe in 2000 and set a new record by drilling 434 wells, most of which were shallow gas. Key producing areas were Sandhills, Blackfoot and Grande Prairie (Wapiti). All three show upside potential for the future, along with the Waskada and Twining fields. Also in 2000, the Calgary Division acquired a small Canadian producer, Q Energy Limited, which had assets adjacent to EOG's existing Sandhills operation.

For 2001 and beyond, the division is broadening its strategy by seeking large reserve targets in Canadian producing basins. It made a significant step toward meeting this goal last year by acquiring a significant acreage position of about 240,000 net acres in the central Mackenzie corridor of the Northwest Territories. The division added to its exploration portfolio with the identification and development of a significant potential of an ineffective waterflood at Waskada, Manitoba. Plans are to enter the first phase of the redevelopment of the reservoir during 2001.

During the coming year, the division plans to drill at least 375 shallow gas wells in the Sandhills and Blackfoot areas and carry out further seismic and aeromagnetic surveys on the Northwest Territories acreage where drilling is planned for early 2002.

"People are the key to unlocking the many unique and varied opportunities that are waiting to be discovered. Make sure they understand what it takes to make money and then give them some rein and let them run."
Lanny Fenwick,
Senior Vice President &
General Manager, EOG
Resources Canada Inc.

International Division

> ***"EOG's international division has really been rebuilt within the last 12 months. With our small group of seasoned professionals, we have developed a competitive edge to quickly screen, evaluate, and decide the merits of an opportunity as we search the international arena for the right fit."***
> ***Sammy Pickering, Engineering Director***

2000 got underway in the International Division with the announcement that EOG had signed an ammonia plant contract in Trinidad and received approval from the Government of Trinidad and Tobago to supply 60 MMcf/d of natural gas to this facility. To support the contract, EOG drilled an appraisal well on the U(a) block and increased proved reserves to 746 Bcfe.

EOG's blocks in Trinidad include the SECC and the U(a). All current production is from the SECC block, where production increased from 138 MMcfe/d in 1999 to 141 MMcfe/d in 2000. The SECC block production is under a take-or-pay contract with the National Gas Company of Trinidad. Initial natural gas sales from the U(a) block and ammonia production should start in the latter part of 2002.

"EOG is one of the few large independents who has been successful in adding value through niche international projects. We will continue to grow our business in Trinidad and add a mix of quality international projects to our portfolio."
Lindy Looger, Vice President & General Manager, EOG Resources Trinidad Ltd. & Gerald Colley, Vice President & General Manager, International Division

Financial Review

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2000 should be read in conjunction with the consolidated financial statements of EOG Resources, Inc. ("EOG") and notes thereto beginning with page 26. As a result of the consensus of Emerging Issues Task Force Issue 00-10, "Accounting for Shipping and Handling Fees and Costs," EOG reclassified all prior periods to reflect certain transportation expenses incurred as lease and well expenses, instead of deductions from revenues as previously reported.

Results of Operations

Net Operating Revenues. Wellhead volume and price statistics for the specified years were as follows:

	Year Ended December 31,		
	2000	1999	1998
Natural Gas Volumes (MMcf per day)			
United States	**654**	654	671[1]
Canada	**129**	115	105
Trinidad	**125**	123	139
India[2]	**-**	46	56
Total	**908**	938	971
Average Natural Gas Prices ($/Mcf)			
United States	**$ 3.96**	$ 2.20	$ 2.01[3]
Canada	**3.33**	1.88	1.48
Trinidad	**1.17**	1.08	1.06
India[2]	**-**	2.09	2.57
Composite	**3.49**	2.01	1.85
Crude Oil and Condensate Volumes (MBbl per day)			
United States	**22.8**	14.4	14.0
Canada	**2.1**	2.6	2.6
Trinidad	**2.6**	2.4	3.0
India[2]	**-**	4.1	5.1
Total	**27.5**	23.5	24.7
Average Crude Oil and Condensate Prices ($/Bbl)			
United States	**$ 29.68**	$ 18.55	$ 12.89
Canada	**27.76**	16.77	11.82
Trinidad	**30.14**	16.21	12.26
India[2]	**-**	12.80	12.86
Composite	**29.57**	17.12	12.69

	Year Ended December 31,		
	2000	1999	1998
Natural Gas Liquids Volumes (MBbl per day)			
United States	**4.0**	2.6	2.9
Canada	**0.7**	0.8	1.0
Total	**4.7**	3.4	3.9
Average Natural Gas Liquids Prices ($/Bbl)			
United States	**$ 20.45**	$ 13.41	$ 9.50
Canada	**16.75**	8.23	5.32
Composite	**19.87**	12.24	8.38
Natural Gas Equivalent Volumes (MMcfe per day)[4]			
United States	**814**	757	771
Canada	**146**	134	128
Trinidad	**141**	138	157
India[2]	**-**	70	86
Total	**1,101**	1,099	1,142
Total Bcfe Deliveries	**403**	401	417

(1) Includes 48 MMcf per day delivered under the terms of a volumetric production payment agreement effective October 1, 1992, as amended. Delivery obligations were terminated in December 1998.
(2) See Note 4 to the Consolidated Financial Statements regarding the Share Exchange Agreement with Enron Corp.
(3) Includes an average equivalent wellhead value of $1.88 per Mcf for the volumes detailed in note (1).
(4) Includes natural gas, crude oil, condensate and natural gas liquids.

2000 compared to 1999. During 2000, net operating revenues increased $648 million to $1,490 million. Total wellhead revenues of $1,491 million increased by $641 million, or 75%, as compared to 1999.

Average wellhead natural gas prices for 2000 were approximately 74% higher than the comparable period in 1999, increasing net operating revenues by $491 million. Average wellhead crude oil and condensate prices were up by 73%, increasing net operating revenues by $125 million. Wellhead natural gas volumes were approximately 3% lower than the comparable period in 1999, decreasing net operating revenues by $20 million. The decrease in wellhead natural gas volumes is primarily due to the transfer of producing properties in connection with the Share Exchange Agreement ("Share Exchange") described in Note 4 to the Consolidated Financial Statements, partially offset by increased deliveries in Canada and Trinidad. Wellhead crude oil and condensate volumes were 17% higher than in 1999, increasing net operating revenues by $26 million. The increase in wellhead crude oil and condensate volumes is primarily due to increased deliveries in the United States and Trinidad, partially offset by the transfer of producing properties in the Share Exchange and decreased deliveries in Canada. Natural gas liquids prices and deliveries were approximately 62%

and 39% higher than 1999, increasing net operating revenues by $13 million and $6 million, respectively.

Gains (losses) on sales of reserves and related assets and other, net totaled a gain of $8 million during 2000 compared to a loss of nearly $1 million in 1999. The difference is due primarily to a $7 million gain on sales of certain North America properties in 2000.

Other marketing activities associated with sales and purchases of natural gas, and natural gas and crude oil price hedging and trading transactions decreased net operating revenue by $10 million during 2000, compared to a $7 million reduction in 1999.

1999 compared to 1998. During 1999, net operating revenues increased $34 million to $842 million. Total wellhead revenues of $850 million increased by $69 million, or 9%, as compared to 1998.

Average wellhead natural gas prices for 1999 were approximately 9% higher than the comparable period in 1998 increasing net operating revenues by approximately $56 million. Average wellhead crude oil and condensate prices were up by 35% increasing net operating revenues by $38 million. Revenues from the sale of natural gas liquids increased $3 million primarily due to higher wellhead prices. Wellhead natural gas volumes were approximately 3% lower than the comparable period in 1998 decreasing net operating revenues by nearly $22 million. The decrease in volumes is primarily due to the transfer of producing properties in the Share Exchange and decreased deliveries in Trinidad. Production in Trinidad decreased 16 MMcf per day due primarily to decreased nominations and the temporary shut-in of a well in accordance with the terms of a field allocation agreement. North America wellhead natural gas production was approximately 1% lower than the comparable period in 1998. Wellhead crude oil and condensate volumes were 5% lower than in 1998 decreasing net operating revenues by $6 million. The decrease is primarily attributable to the Share Exchange and decreased deliveries in Trinidad.

Gains (losses) on sales of reserves and related assets and other, net totaled a loss of $1 million during 1999 compared to a net gain of $18 million in 1998. The difference is due primarily to an $8 million loss in 1999 related to the anticipated disposition of certain international assets compared to a $27 million gain on sale of certain South Texas properties, partially offset by a $14 million provision for loss on certain physical natural gas contracts in 1998.

Other marketing activities associated with sales and purchases of natural gas, natural gas and crude oil price hedging and trading transactions, and margins related to the volumetric production payment (in 1998) decreased net operating revenue by $7 million during 1999, compared to a $9 million addition in 1998.

Operating Expenses

2000 compared to 1999. During 2000, operating expenses of $793 million were approximately $31 million lower than the $824 million incurred in 1999.

Lease and well expenses increased $9 million to $141 million primarily due to continually expanding operations and increases in production activity in North America. Exploration expenses of $67 million and dry hole expenses of $17 million increased $14 million and $5 million, respectively, from 1999 due to increased exploratory drilling activities. Impairment of unproved oil and gas properties increased $4 million to $36 million as a result of increased acquisition of unproved leases in North America. Depreciation, depletion and amortization ("DD&A") expense decreased $90 million primarily due to charges of $15 million pursuant to a change in EOG's strategy related to certain offshore operations in the second quarter of 1999, the impairment of various North America properties in the fourth quarter of 1999, and non-recurring charges of $114 million related primarily to assets determined no longer central to EOG's business in the third quarter of 1999. General and administrative ("G&A") expenses decreased $16 million primarily due to non-recurring costs in 1999 of $14 million related to the Share Exchange, the potential sale of EOG and personnel expenses partially offset by savings resulting from the discontinuance of the India and China operations as a result of the Share Exchange. Taxes other than income increased $42 million reflecting higher state severance taxes associated with higher taxable wellhead revenues resulting from higher average prices.

Total operating costs per unit of production, which include lease and well, DD&A, G&A, taxes other than income and interest expense, decreased 7% to $1.82 per thousand cubic feet equivalent ("Mcfe") in 2000 from $1.97 in 1999. This decrease is primarily due to lower per unit rates of DD&A and G&A, partially offset by higher per unit rates of taxes other than income and lease and well. Excluding the aforementioned 1999 charges of $15 million and $114 million in DD&A and $14 million in G&A, the per unit operating costs for EOG were $1.61 per Mcfe in 1999. The per unit operating costs in 2000 of $1.82 was $0.21 higher than this adjusted per unit operating costs of 1999 primarily due to a higher per unit rate of DD&A, taxes other than income and lease and well expense.

1999 compared to 1998. During 1999, operating expenses of $824 million were approximately $129 million higher than the $695 million incurred in 1998.

Lease and well expenses decreased $6 million to $132 million primarily due to the effects of the Share Exchange, fewer workovers, the effects of a warm winter and a continuing focus on controlling operating costs in all areas of EOG operations. Exploration expenses of $53 million and dry hole expenses of $12 million decreased $13 million and $11 million, respectively, from 1998 primarily due to implementation of cost provisions of certain new service agreements in North America. Impairment of unproved oil and gas properties of $32 million remained essentially flat compared to 1998. DD&A expense increased approximately $145 million to $460 million in 1999 primarily due to charges of $15 million pursuant to a change in EOG's strategy related to certain offshore operations in the second quarter and an impairment of various North America properties in the fourth quarter, and non-recurring charges of $114 million related primarily to assets determined no longer central to EOG's business in the third quarter. G&A expenses were $14 million higher than in 1998 due to non-recurring costs of $5 million related to the potential sale of EOG, $4 million related to personnel expenses and $9 million related to the completion of the Share Exchange partially offset by a reduction of $4 million resulting from the discontinuance of the India and China operations as a result of the Share Exchange.

Total operating costs per unit of production, which include lease and well, DD&A, G&A, taxes other than income and interest expense, increased 32% to $1.97 per Mcfe in 1999 from $1.49 per Mcfe in 1998. This increase is primarily due to a higher per unit rate of DD&A, G&A and interest expense. Excluding the aforementioned charges of $15 million and $114 million in DD&A and $14 million in G&A, the per unit operating costs for EOG were $1.61 per Mcfe. The adjusted per unit operating costs were $0.12 higher compared to $1.49 per Mcfe for the comparable period in 1998 primarily due to a higher per unit rate of interest as a result of higher debt levels and a higher per unit rate of DD&A expense.

Other Income (Expense). Other income of $611 million for 1999 included a $575 million net gain from the Share Exchange, a $59.6 million gain on the sale of 3.2 million options owned by EOG to purchase Enron Corp. common stock, and a $19.4 million charge for estimated exit costs related to EOG's decision to dispose of certain international assets.

Interest Expense. The increase in net interest expense of $13 million from 1998 to 1999 primarily reflects a higher level of debt outstanding due to expanded worldwide operations and common stock repurchases (See Note 2 to the Consolidated Financial Statements).

Income Taxes. Income tax provision increased approximately $238 million for 2000 as compared to 1999 as a result of a higher pre-tax income year to year after removing the non-taxable gain on the Share Exchange in 1999. Income tax provision decreased approximately $5 million for 1999 as compared to 1998 primarily due to lower pre-tax income year to year after removing the non-taxable gain on the Share Exchange in 1999.

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the three-year period ended December 31, 2000 included funds generated from operations, proceeds from the sales of other assets, selected oil and gas reserves and related assets, funds from new borrowings and proceeds from equity offerings. Primary cash outflows included funds used in operations, exploration and development expenditures, common stock repurchases, dividends paid to EOG shareholders, repayments of debt and cash contributed to transferred subsidiaries in the Share Exchange.

Net operating cash flows of $967 million in 2000 increased approximately $524 million as compared to 1999 due to higher net operating revenues resulting from higher prices, net of cash operating expenses, and higher tax benefits from stock options exercised partially offset by higher current income taxes. Changes in working capital and other liabilities decreased operating cash flows by $16 million as compared to 1999 primarily due to changes in accounts receivable, accrued royalties payable and accrued production taxes caused by fluctuation of commodity prices at each yearend. Net investing cash outflows of $667 million in 2000 increased by $304 million as compared to 1999 due primarily to increased exploration and development expenditures of $231 million (including producing property acquisitions), increased equity investments, and the non-recurrence of proceeds from sales of Enron Corp. options in 1999, partially offset by increased proceeds from sales of reserves and related assets. 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 materials and equipment used in drilling and related activities. Cash used in financing activities in 2000 was $305 million as compared to $62 million in 1999. Financing activities in 2000 included repayments of debt of $131 million, common stock repurchases of $273 million and dividend payments of $26 million, partially offset by proceeds from sales of treasury stock of $127 million.

Net operating cash flows of $444 million in 1999 increased approximately $40 million as compared to 1998 due to higher net operating revenues resulting from higher prices, net of cash operating expenses, and lower current income taxes. Changes in working capital and other liabilities decreased operating cash flows by $18 million as compared to 1998 primarily due to changes in accounts receivable, accrued royalties payable and accrued production taxes caused by fluctuation of commodity prices at each yearend. Net investing cash outflows of $363 million in 1999 decreased by $396 million as compared to 1998 due primarily to decreased exploration and development expenditures of $312 million (including producing property acquisitions) and higher proceeds from sales of other assets of $83 million partially offset by lower proceeds from sales of reserves and related assets of $51 million. Changes in components of working capital associated with investing activities included for all periods changes in accounts payable related to the accrual of exploration and development expenditures and changes in inventories which represent materials and equipment used in drilling and related activities. Cash used in financing activities in 1999 was $62 million as compared to cash provided by financing activities of $353 million in 1998. Financing activities in 1999 included funds used in the Share Exchange of $609 million, dividend payments of $17 million, transaction fees of $19 million associated with the Share Exchange and other financing transactions, and net repayment of $152 million of long-term debt, partially offset by net proceeds from common and preferred equity offerings of $725 million and proceeds from sales of treasury stock of $13 million.

Discretionary cash flow available to common, a frequently used measure of performance for exploration and production companies, is generally derived by adjusting net income to include tax benefits on stock options exercised and to eliminate the effects of depreciation, depletion and amortization, impairment of unproved oil and gas properties, deferred income taxes, gains on sales of oil and gas reserves and related assets, certain other non-cash amounts, except for amortization of deferred revenue and exploration and dry hole costs. EOG generated discretionary cash flow available to common of approximately $1,007 million in 2000, $477 million in 1999 and $463 million in 1998. Discretionary cash flow available to common should not be considered as an alternative to income from operations or to cash flows from operating activities (as determined in accordance with accounting principles generally accepted in the United States) and should not be construed as an indication of a company's operating performance or as a measure of liquidity.

Exploration and Development Expenditures. The table below sets out components of actual exploration and development expenditures for the years ended December 31, 2000, 1999 and 1998, along with the total budgeted for 2001, excluding acquisitions.

Expenditure Category	Actual			Excluding India and China Operations		Budgeted 2001 (excluding acquisitions)
(In Millions)	**2000**	1999	1998	1999	1998	
Capital						
Drilling and Facilities	**$ 443**	$ 319	$ 420	$ 293	$ 373	
Leasehold Acquisitions	**51**	21	36	21	36	
Producing Property Acquisitions	**102**	45	211	43	211	
Capitalized Interest	**7**	11	13	8	9	
Subtotal	**603**	396	680	365	629	
Exploration Costs	**67**	53	66	51	64	
Dry Hole Costs	**17**	12	23	12	23	
Total	**$ 687**	$ 461	$ 769	$ 428	$ 716	$700 - $800

Exploration and development expenditures increased $226 million in 2000 as compared to 1999 primarily due to increased exploration and development activities in the United States and Trinidad, and acquisitions of oil and gas properties in North America, partially offset by the Share Exchange and the acquisition of producing properties in the Big Piney area in the first quarter of 1999.

Hedging Transactions. EOG's 2000 NYMEX-related natural gas and crude oil commodity price swaps decreased net operating revenues by $11 million and $6 million, respectively. At December 31, 2000, there were open crude oil commodity price swaps for 2001 covering approximately 0.7 MMBbl of crude oil at a weighted average price of $26.25 per barrel. There were no open natural gas commodity price swaps.

Financing. EOG's long-term debt-to-total-capital ratio was 38% as of December 31, 2000 compared to 47% as of December 31, 1999.

During 2000, total long-term debt decreased $131 million to $859 million primarily due to higher cash flow from operations primarily resulting from higher oil and gas prices, partially offset by additions to oil and gas properties and significant share repurchases of common stock. (See Note 2 to the Consolidated Financial Statements). The estimated fair value of EOG's long-term debt at December 31, 2000 and 1999 was $831 million and $933 million, respectively, based upon quoted market prices and, where such prices were not available, upon interest rates currently available to EOG at yearend. EOG's debt is primarily at fixed interest rates. At December 31, 2000, a 1% change in interest rates would result in a $44 million change in the estimated fair value of the fixed rate obligations. (See Note 12 to the Consolidated Financial Statements).

Shelf Registration. During the third quarter of 2000, EOG filed a shelf registration statement for the offer and sale from time to time of up to $600 million of EOG debt securities, preferred stock and/or common stock. Such registration statement was declared effective by the Securities and Exchange Commission on October 27, 2000. As of February 15, 2001, EOG had sold no securities pursuant to this shelf registration. When combined with the unused portion of a previously filed registration statement declared effective in January 1998, such registration statements provide for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock by EOG in an aggregate amount up to $688 million.

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 North America natural gas and crude oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. This divergence in opinion is caused by various factors including improvements in the technology used in drilling and completing crude oil and natural gas wells, improvements being realized in the availability and utilization of natural gas storage capacity and colder weather experienced in the latter part of 2000. However, the increasing recognition of natural gas as a more environmentally friendly source of energy along with the availability of significant domestically sourced supplies should result in further 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. At December 31, 2000, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2001 for which prices have not, in effect, been hedged using NYMEX-related commodity market transactions and long-term marketing contracts, EOG's price sensitivity for each $.10 per Mcf change in average wellhead natural gas prices is $19 million (or $0.16 per share) for net income and $19 million for current operating cash flow. EOG is not impacted as significantly by changing crude oil prices for those volumes not otherwise hedged. EOG's price sensitivity for each $1.00 per barrel change in average wellhead crude oil prices is $6 million (or $0.05 per share) for net income and $6 million for current operating cash flow.

EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in North America. However, in order to diversify its overall asset portfolio and as a result of its overall success realized in Trinidad, EOG anticipates expending a portion of its available funds in the further development of opportunities outside North America. In addition, EOG expects to conduct limited exploratory activity in other areas outside of North America and will continue to evaluate the potential for involvement in other exploitation type opportunities. Budgeted 2001 expenditures, excluding acquisitions, are in the range of $700 - $800 million, addressing the continuing uncertainty with regard to the future of the North America natural gas and crude oil and condensate price environment. Budgeted expenditures for 2001 are structured to maintain the flexibility necessary under EOG's continuing strategy of funding North America exploration, exploitation, development and acquisition activities primarily from available internally generated cash flow.

The level of exploration and development expenditures may vary in 2001 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 2001 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 Trinidad, such commitments are not anticipated 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, may affect EOG's operations and costs as a result of their effect on natural gas and crude oil exploration, exploitation, development and production operations. Compliance with such laws and regulations 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 by reason of environmental laws and regulations. However, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance.

New Accounting Pronouncement - SFAS No. 133

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133--"Accounting for Derivative Instruments and Hedging Activities" effective for fiscal years beginning after June 15, 1999. In June 1999, the FASB issued SFAS No. 137, which delayed the effective date of SFAS No. 133 for one year, to fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, which amends the accounting and reporting standards of SFAS No. 133 for certain derivative instruments and certain hedging activities. SFAS No. 133, as amended by SFAS No. 137 and No. 138, cannot be applied retroactively and must be applied to (a) derivative instruments and (b) certain derivative instruments embedded in hybrid contracts that were issued, acquired or substantively modified after a transition date to be selected by EOG of either December 31, 1997 or December 31, 1998.

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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the statements of income and requires a company to formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

EOG adopted SFAS No. 133, as amended by SFAS No. 137 and No. 138, on January 1, 2001 for the accounting periods which begin thereafter. The adoption of SFAS No. 133 did not have a material impact on EOG's financial statements.

Information Regarding Forward-Looking Statements

This Annual Report 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" 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 or the ability to increase reserves or 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: timing and extent of changes in commodity prices for crude oil, natural gas and related products and interest rates; extent of EOG's success in discovering, developing, marketing and producing reserves and in acquiring oil and gas properties; political developments around the world; 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.

Report of Independent Public Accountants

To EOG Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2000 and 1999, 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, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of EOG Resources, Inc. and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Houston, Texas
February 15, 2001

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 accounting principles generally accepted in the United States and, accordingly, include some amounts that are based on the best estimates and judgments of management.

Arthur Andersen LLP, independent public accountants, was engaged to audit the consolidated financial statements of EOG and issue a report thereon. In the conduct of the audit, Arthur Andersen 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 Arthur Andersen LLP during the audit were valid and appropriate.

The system of internal controls of EOG is designed to provide reasonable assurance as to the reliability of financial statements and the protection of assets from unauthorized acquisition, use or disposition. This system includes, but is not limited to, written policies and guidelines including a published code for the conduct of business affairs, conflicts of interest and compliance with laws regarding antitrust, antiboycott and foreign corrupt practices policies, the careful selection and training of qualified personnel, and a documented organizational structure outlining the separation of responsibilities among management representatives and staff groups.

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 direct access to the Audit Committee and meet with the committee from time to time to discuss accounting, auditing and financial reporting matters. It should be recognized that there are inherent limitations to the effectiveness of any system of internal control, including the possibility of human error and circumvention or override. Accordingly, even an effective system can provide only reasonable assurance with respect to the preparation of reliable financial statements and safeguarding of assets. Furthermore, the effectiveness of an internal control system can change with circumstances.

It is management's opinion that, considering the criteria for effective internal control over financial reporting and safeguarding of assets which consists of interrelated components including the control environment, risk assessment process, control activities, information and communication systems, and monitoring, EOG maintained an effective system of internal control as to the reliability of financial statements and the protection of assets against unauthorized acquisition, use or disposition during the year ended December 31, 2000.

Timothy K. Driggers
Vice President, Accounting
and Land Administration

Edmund P. Segner, III
President and Chief of Staff

Mark G. Papa
Chairman and
Chief Executive Officer

Houston, Texas
February 15, 2001

Consolidated Statements of Income and Comprehensive Income

(In Thousands, Except Per Share Amounts)	Year Ended December 31, 2000	1999	1998
Net Operating Revenues			
Natural Gas	$ 1,155,804	$ 683,469	$ 658,949
Crude Oil, Condensate and Natural Gas Liquids	325,726	159,373	131,052
Gains (Losses) on Sales of Reserves and Related Assets and Other, Net	8,365	(743)	18,251
Total	1,489,895	842,099	808,252
Operating Expenses			
Lease and Well	140,915	132,233	137,932
Exploration Costs	67,196	52,773	65,940
Dry Hole Costs	17,337	11,893	22,751
Impairment of Unproved Oil and Gas Properties	35,717	31,608	32,076
Depreciation, Depletion and Amortization	370,026	459,877	315,106
General and Administrative	66,932	82,857	69,010
Taxes Other Than Income	94,909	52,670	51,776
Total	793,032	823,911	694,591
Operating Income	696,863	18,188	113,661
Other Income (Expense)			
Gain on Share Exchange	–	575,151	–
Other, Net	(2,300)	36,192	(4,800)
Total	(2,300)	611,343	(4,800)
Income Before Interest Expense and Income Taxes	694,563	629,531	108,861
Interest Expense			
Incurred	67,714	72,413	61,290
Capitalized	(6,708)	(10,594)	(12,711)
Net Interest Expense	61,006	61,819	48,579
Income Before Income Taxes	633,557	567,712	60,282
Income Tax Provision (Benefit)	236,626	(1,382)	4,111
Net Income	396,931	569,094	56,171
Preferred Stock Dividends	(11,028)	(535)	–
Net Income Available to Common	$ 385,903	$ 568,559	$ 56,171
Earnings Per Share available to Common			
Basic	$ 3.30	$ 4.04	$ 0.36
Diluted	$ 3.24	$ 4.01	$ 0.36
Average Number of Common Shares			
Basic	116,934	140,648	154,002
Diluted	119,102	141,627	154,573
Net Income	$ 396,931	$ 569,094	$ 56,171
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustment	(12,338)	16,038	(16,077)
Unrealized Gain on Available-for-Sale Security, Net of Tax of $211	392	–	–
Comprehensive Income	$ 384,985	$ 585,132	$ 40,094

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

Consolidated Balance Sheets

(In Thousands)	At December 31, 2000	1999
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 20,152**	$ 24,836
Accounts Receivable	**342,579**	148,189
Inventories	**16,623**	18,816
Other	**15,073**	8,660
Total	**394,427**	200,501
Oil and Gas Properties (Successful Efforts Method)	**5,122,728**	4,602,740
Less: Accumulated Depreciation, Depletion and Amortization	**(2,597,721)**	(2,267,812)
Net Oil and Gas Properties	**2,525,007**	2,334,928
Other Assets	**81,381**	75,364
Total Assets	**$ 3,000,815**	$ 2,610,793
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts Payable	**$ 246,030**	$ 172,780
Accrued Taxes Payable	**78,838**	19,648
Dividends Payable	**4,525**	4,227
Other	**40,285**	21,963
Total	**369,678**	218,618
Long-Term Debt	**859,000**	990,306
Other Liabilities	**51,133**	46,306
Deferred Income Taxes	**340,079**	225,952
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series B, 100,000 shares Issued, Cumulative, $100,000,000 Liquidation Preference	**97,879**	97,909
Series D, 500 shares Issued, Cumulative, $50,000,000 Liquidation Preference	**49,285**	49,281
Common Stock, $.01 Par, 320,000,000 shares Authorized and 124,730,000 shares Issued	**201,247**	201,247
Additional Paid In Capital	**4,221**	–
Unearned Compensation	**(3,756)**	(1,618)
Accumulated Other Comprehensive Income	**(31,756)**	(19,810)
Retained Earnings	**1,301,067**	930,938
Common Stock Held in Treasury, 7,825,708 shares at December 31, 2000 and 5,625,446 shares at December 31, 1999	**(237,262)**	(128,336)
Total Shareholders' Equity	**1,380,925**	1,129,611
Total Liabilities and Shareholders' Equity	**$ 3,000,815**	$ 2,610,793

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	Retained Earnings	Common Stock Held In Treasury	Total Shareholders' Equity
Balance at December 31, 1997	$ –	$ 201,600	$ 402,877	$ (4,694)	$ (19,771)	$ 800,709	$ (99,672)	$1,281,049
Net Income	–	–	–	–	–	56,171	–	56,171
Common Stock Dividends Paid/ Declared, $.12 Per Share	–	–	–	–	–	(18,509)	–	(18,509)
Translation Adjustment	–	–	–	–	(16,077)	–	–	(16,077)
Treasury Stock Purchased	–	–	–	–	–	–	(25,875)	(25,875)
Treasury Stock Issued Under Stock Option Plans	–	–	(762)	(1,709)	–	–	5,104	2,633
Tax Benefits from Stock Options Exercised	–	–	270	–	–	–	–	270
Amortization of Unearned Compensation	–	–	–	1,503	–	–	–	1,503
Other	–	–	(861)	–	–	–	–	(861)
Balance at December 31, 1998	–	201,600	401,524	(4,900)	(35,848)	838,371	(120,443)	1,280,304
Net Income	–	–	–	–	–	569,094	–	569,094
Preferred Stock Issued	147,175	–	–	–	–	–	–	147,175
Amortization of Preferred Stock Discount	15	–	–	–	–	–	–	15
Common Stock Issued	–	270	577,662	–	–	–	–	577,932
Preferred Stock Dividends Paid/Declared	–	–	–	–	–	(535)	–	(535)
Common Stock Dividends Paid/ Declared, $.12 Per Share	–	–	–	–	–	(16,377)	–	(16,377)
Translation Adjustment	–	–	–	–	16,038	–	–	16,038
Treasury Stock Purchased	–	–	–	–	–	–	(2,143)	(2,143)
Treasury Stock Received in Share Exchange	–	–	–	–	–	–	(1,459,484)	(1,459,484)
Common Stock Retired	–	(623)	(978,224)	–	–	(458,033)	1,436,880	–
Treasury Stock Issued Under Stock Option Plans	–	–	(2,274)	136	–	(1,582)	16,854	13,134
Tax Benefits from Stock Options Exercised	–	–	1,387	–	–	–	–	1,387
Amortization of Unearned Compensation	–	–	–	3,146	–	–	–	3,146
Other	–	–	(75)	–	–	–	–	(75)
Balance at December 31, 1999	147,190	201,247	–	(1,618)	(19,810)	930,938	(128,336)	1,129,611
Net Income	–	–	–	–	–	396,931	–	396,931
Amortization of Preferred Stock Discount	419	–	–	–	–	(419)	–	–
Exchange Offer Fees	(445)	–	–	–	–	–	–	(445)
Preferred Stock Dividends Paid/Declared	–	–	–	–	–	(10,609)	–	(10,609)
Common Stock Dividends Paid/ Declared, $.135 Per Share	–	–	–	–	–	(15,774)	–	(15,774)
Translation Adjustment	–	–	–	–	(12,338)	–	–	(12,338)
Unrealized Gain on Available-for-Sale Security	–	–	–	–	392	–	–	392
Treasury Stock Purchased	–	–	–	–	–	–	(272,723)	(272,723)
Treasury Stock Issued Under Stock Option Plans	–	–	(36,701)	–	–	–	163,350	126,649
Tax Benefits from Stock Options Exercised	–	–	41,307	–	–	–	–	41,307
Restricted Stock and Units	–	–	2,805	(3,411)	–	–	606	–
Amortization of Unearned Compensation	–	–	–	1,273	–	–	–	1,273
Equity Derivative Transactions	–	–	(3,190)	–	–	–	–	(3,190)
Other	–	–	–	–	–	–	(159)	(159)
Balance at December 31, 2000	$147,164	$201,247	$ 4,221	$ (3,756)	$ (31,756)	$1,301,067	$(237,262)	$1,380,925

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

Consolidated Statements of Cash Flows

(In Thousands)	2000	1999	1998
	Year Ended December 31,		
Cash Flows from Operating Activities			
Reconciliation of Net Income to Net Operating Cash Inflows:			
Net Income	**$ 396,931**	$ 569,094	$ 56,171
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	**370,026**	459,877	315,106
Impairment of Unproved Oil and Gas Properties	**35,717**	31,608	32,076
Deferred Income Taxes	**97,729**	(26,252)	(26,794)
Other, Net	**6,693**	25,583	7,761
Exploration Costs	**67,196**	52,773	65,940
Dry Hole Costs	**17,337**	11,893	22,751
Losses (Gains) On Sales of Reserves and Related Assets and Other, Net	**(5,977)**	5,602	(11,191)
Gains on Sales of Other Assets	**–**	(59,647)	–
Gain on Share Exchange	**–**	(575,151)	–
Tax Benefits from Stock Options Exercised	**41,307**	1,387	270
Other, Net	**(8,935)**	(19,081)	1,116
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	**(191,492)**	(12,914)	36,363
Inventories	**2,345**	5,180	(7,541)
Accounts Payable	**97,374**	4,395	(65,249)
Accrued Taxes Payable	**54,556**	2,449	(8,754)
Other Liabilities	**348**	(15,438)	2,324
Other, Net	**11,378**	(9,960)	(3,620)
Amortization of Deferred Revenue	**–**	–	(43,344)
Changes in Components of Working Capital			
Associated with Investing and Financing Activities	**(25,123)**	(7,879)	30,491
Net Operating Cash Inflows	**967,410**	443,519	403,876
Investing Cash Flows			
Additions to Oil and Gas Properties	**(602,638)**	(396,450)	(680,520)
Exploration Costs	**(67,196)**	(52,773)	(65,940)
Dry Hole Costs	**(17,337)**	(11,893)	(22,751)
Proceeds from Sales of Reserves and Related Assets	**26,189**	10,934	61,858
Proceeds from Sales of Other Assets	**–**	82,965	–
Changes in Components of Working Capital			
Associated with Investing Activities	**22,798**	7,909	(30,173)
Other, Net	**(28,977)**	(4,057)	(22,094)
Net Investing Cash Outflows	**(667,161)**	(363,365)	(759,620)
Financing Cash Flows			
Long-Term Debt			
Trade	**(131,306)**	47,527	394,004
Affiliate	**–**	(200,000)	7,500
Proceeds from Preferred Stock Issued	**–**	147,175	–
Proceeds from Common Stock Issued	**–**	577,932	–
Dividends Paid	**(26,071)**	(17,395)	(18,504)
Treasury Stock Purchased	**(272,723)**	(2,143)	(25,875)
Proceeds from Sales of Treasury Stock	**127,090**	13,341	2,613
Equity Contribution to Transferred Subsidiaries	**–**	(608,750)	–
Other, Net	**(1,923)**	(19,308)	(7,021)
Net Financing Cash Inflows (Outflows)	**(304,933)**	(61,621)	352,717
Increase (Decrease) in Cash and Cash Equivalents	**(4,684)**	18,533	(3,027)
Cash and Cash Equivalents at Beginning of Year	**24,836**	6,303	9,330
Cash and Cash Equivalents at End of Year	**$ 20,152**	$ 24,836	$ 6,303

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

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements of EOG Resources, Inc. ("EOG"), a Delaware corporation, include the accounts of all domestic and foreign subsidiaries. All material intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for prior years to conform with the current presentation.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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.

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 significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Amortization of any remaining costs of such leases begins at a point prior to the end of the lease term depending upon the length of such term. 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. If proved commercial reserves are not discovered, such drilling costs are expensed. 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. Estimated future dismantlement, restoration and abandonment costs (classified as long-term liabilities), net of salvage values, are taken into account. Certain other assets are depreciated on a straight-line basis. Periodically, or 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 and operating costs and anticipated production from proved reserves 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 changes in value.

Natural gas 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 may differ from an owner's ownership percentage. Under entitlement accounting, a receivable is recorded when underproduction occurs and a payable when overproduction occurs.

Gains and losses associated with the sale of in place natural gas and crude oil reserves and related assets are classified as net operating revenues in the consolidated statements of income and comprehensive income based on EOG's strategy of continuing such sales in order to maximize the economic value of its assets.

New Accounting Pronouncements in 2000. In July 2000, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board reached a consensus on EITF Issue 00-15, "Classification in the Statement of Cash Flows of the Income Tax Benefit Received by a Company upon Exercise of a Nonqualified Employee Stock Option." Pursuant to the consensus, reduction of income taxes paid as a result of the deduction triggered by employee exercise of stock options should be classified as an operating cash inflow. In accordance with EITF Issue 00-15, EOG reported tax benefits from stock options exercised as an operating cash inflow for the year 2000 and reclassified the amounts in the prior periods on the consolidated statements of cash flows to conform with the current year classification.

In September 2000, the EITF reached a consensus on EITF Issue 00-10, "Accounting for Shipping and Handling Fees and Costs." Pursuant to the consensus, amounts paid related to certain transportation must be reported as an expense on the income statement rather than reporting revenues net of transportation as has been industry practice. In addition, pertinent amounts in financial statements for prior periods should be reclassified to reflect the same accounting treatment. In accordance with EITF Issue 00-10, EOG recorded transportation related amounts of $29.4 million, $40.7 million and $39.1 million in lease and well expense with a corresponding increase to revenues for 2000, 1999 and 1998, respectively, in the consolidated statements of income and comprehensive income.

Accounting for Price Risk Management Activities. EOG engages in price risk management activities from time to time primarily for non-trading and to a lesser extent for trading purposes. Derivative financial instruments (primarily price swaps and costless collars) are utilized selectively for non-trading purposes to hedge the impact of market fluctuations on natural gas and crude oil market prices. Hedge accounting is utilized in non-trading activities when there is a high degree of correlation between price movements in the derivative and the item designated as being hedged. Gains and losses on derivative financial instruments used for hedging purposes are recognized as revenue in the same period as the hedged item. Gains and losses on hedging instruments that are closed prior to maturity are deferred in the consolidated balance sheets and recognized as revenue in the same period as the hedged item. In instances where the anticipated correlation of price movements does not occur, hedge accounting is terminated and future changes in the value of the derivative are recognized as gains or losses using the mark-to-market method of accounting. Derivative and other financial instruments utilized in connection with trading activities, primarily price swaps and call options, are accounted for using the mark-to-market method, under which changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change. The cash flow impact of derivative and other financial instruments used for non-trading and trading purposes is reflected as cash flows from operating activities in the consolidated statements of cash flows. (See Notes 12 and 15 for new accounting pronouncement related to accounting for price risk management activities.)

Capitalized Interest Costs. Certain interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties and in work in progress for development drilling and related facilities with significant cash outlays.

Income Taxes. EOG accounts for income taxes under the provisions of Statement of Financial Accounting Standards ("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 "Income Taxes").

Foreign Currency Translation. For subsidiaries whose functional currency is deemed to be other than the U.S. 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 as a separate component of shareholders' equity. 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 "Net Income Per Share Available to Common" for additional information to reconcile the difference between the Average Number of Common Shares outstanding for basic and diluted net income per share).

2. Long-Term Debt

Long-Term Debt at December 31 consisted of the following:

(In thousands)	2000	1999
Commercial Paper	$ –	$ 123,186
Uncommitted Credit Facilities	38,800	87,000
6.50% Notes due 2004	100,000	100,000
6.70% Notes due 2006	150,000	150,000
6.50% Notes due 2007	100,000	100,000
6.00% Notes due 2008	175,000	175,000
6.65% Notes due 2028	150,000	150,000
Subsidiary Debt due 2001	105,000	105,000
Subsidiary Debt due 2002	40,200	–
Other	–	120
Total	$ 859,000	$ 990,306

EOG maintains two credit facilities with different expiration dates. On July 26, 2000, the $400 million credit facility that was scheduled to expire was renewed for $375 million, thereby reducing aggregate long-term committed credit from $800 million at December 31, 1999 to $775 million. Credit facility expirations are as follows: $375 million in 2001 and $400 million in 2004. With respect to the $375 million expiring in 2001, EOG may, at its option, extend the final maturity date of any advances made under the facility by one full year from the expiration date of the facility, effectively qualifying such debt as long-term. Advances under both agreements bear interest, at the option of EOG, based upon a base rate or a Eurodollar rate. At December 31, 2000, there were no advances outstanding under either of these agreements.

Commercial paper and short-term funding from uncommitted credit facilities provide financing for various corporate purposes and bear interest based upon market rates. 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.

The 6.00% to 6.70% Notes due 2004 to 2028 were issued through public offerings and have effective interest rates of 6.14% to 6.83%. The Subsidiary Debt due 2001 was fully paid in January 2001 by increased borrowings from commercial paper and uncommitted credit facilities. The Subsidiary Debt due 2002 bears interest at variable market-based rates.

At December 31, 2000, the aggregate annual maturities of long-term debt outstanding were $105 million for 2001, $40 million for 2002, none for 2003, $100 million for 2004 and none for 2005.

Shelf Registration. During the third quarter of 2000, EOG filed a shelf registration statement for the offer and sale from time to time of up to $600 million of EOG debt securities, preferred stock and/or common stock. Such registration statement was declared effective by the Securities and Exchange Commission on October 27, 2000. As of February 15, 2001, EOG had sold no securities pursuant to this shelf registration. When combined with the unused portion of a previously filed registration statement declared effective in January 1998, such registration statements provide for the offer and sale from time to time of EOG debt securities, preferred stock and/or common stock by EOG in an aggregate amount up to $688 million.

Fair Value of Long-Term Debt. At December 31, 2000 and 1999, EOG had $859 million and $990 million, respectively, of long-term debt which had fair values of approximately $831 million and $933 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 debtholder 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 yearend.

3. Shareholders' Equity

In February 1998, the Board of Directors authorized the purchase of an aggregate maximum of 10 million shares of common stock of EOG from time to time in the open market to be held in treasury for the purpose of, but not limited to, fulfilling any obligations arising under EOG's stock option plans and any other approved transactions or activities for which such common stock shall be required. In February 2000, as amended in December 2000, the Board of Directors authorized the purchase of an aggregate maximum of 15 million shares of common stock of EOG which replaced the remaining authorization from February 1998. At December 31, 2000 and 1999, 7,825,708 shares and 5,625,446 shares, respectively, were held in treasury under these authorizations.

During the first half of 2000, to supplement its share repurchase program, EOG entered into a series of equity derivative transactions. Settlement alternatives for these equity derivative contracts under all circumstances are at the option of EOG and include physical share, net share and net cash settlement. The transactions were accounted for as equity transactions with premium received recorded to additional paid in capital in the consolidated balance sheets. During the third quarter of 2000, EOG closed substantially all of its equity derivative contracts which were to expire in April 2001 by paying $3.75 million. EOG had one million put options which it had written which were still outstanding at December 31, 2000. The strike price of these options is $18.00 per share, and they expire in April 2001. At December 31, 1999, there were no put options outstanding. At December 31, 1998, there were put options outstanding for 175,000 shares of common stock.

On July 23, 1999, EOG filed a registration statement with the Securities and Exchange Commission for the public offering of 27,000,000 shares of EOG's common stock. The public offering was completed on August 16, 1999, and the net proceeds were used to repay short-term borrowings used to fund a significant portion of the cash capital contribution in connection with the Share Exchange Agreement ("Share Exchange") described in Note 4 "Transactions with Enron Corp. and Related Parties." As a result of the public offering and the retirement of the 62,270,000 shares of EOG's common stock received from Enron Corp. in the Share Exchange transaction, the number of shares of EOG's common stock issued was reduced to 124,730,000 from 160,000,000 prior to the Share Exchange.

The following summarizes shares of common stock outstanding:

(In thousands)	2000	1999	1998
Outstanding at January 1	119,105	153,724	155,064
Repurchased	(8,910)	(130)	(1,590)
Issued Pursuant to Stock			
Options and Stock Plans	6,709	781	250
Retired	–	(62,270)	–
Public Offering	–	27,000	–
Outstanding at December 31	116,904	119,105	153,724

In December 1999, EOG issued the following two series of preferred stock:

Series A. On December 10, 1999, EOG issued 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, with a $1,000 Liquidation Preference per share, in a private transaction. Dividends will be 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 March 15, 2000. The dividend rate may only be adjusted in the event that certain amendments are made to the Dividend Received Percentage, as defined, within the first 18 months of the issuance date. EOG may redeem all or a part of the Series A preferred stock at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The shares may also be redeemable, in whole but not in part, in the event that certain amendments are made to the Dividend Received Percentage. The Series A preferred shares are not convertible into, or exchangeable for, common stock of EOG.

Series C. On December 22, 1999, EOG issued 500 shares of Flexible Money Market Cumulative Preferred Stock, Series C, with a liquidation preference of $100,000 per share, in a private transaction. Dividends will be payable on the shares only if declared by EOG's board of directors and will be cumulative. The initial dividend rate on the shares will be 6.84% until December 15, 2004 (the "Initial Period-End Dividend Payment Date"). Through the Initial Period-End Dividend Payment Date dividends will be payable, if declared, on March 15, June 15, September 15, and December 15 of each year beginning March 15, 2000. The cash dividend rate for each subsequent dividend period will be determined pursuant to periodic auctions conducted in accordance with certain auction procedures. The first auction date will be December 14, 2004. After December 15, 2004 (unless EOG has elected a "Non-Call Period" for a subsequent dividend period), EOG may redeem the shares, in whole or in part, on any dividend payment date at $100,000 per share plus accumulated and unpaid dividends. The shares may also be redeemable, in whole but not in part, in the event that certain amendments are made to the Dividend Received Percentage. The Series C preferred shares are not convertible into, or exchangeable for, common stock of EOG.

During the third quarter of 2000, EOG completed two exchange offers for its preferred stock whereby shares of EOG's Series A preferred stock were exchanged for shares of EOG's Series B preferred stock, and shares of EOG's Series C preferred stock were exchanged for shares of EOG's Series D preferred stock. All preferred shares were validly tendered and not withdrawn prior to expiration of the offers. EOG accepted all of the tendered shares and issued the respective series in exchange. Both exchange offers were registered under the Securities Act of 1933. The Series B preferred stock has substantially the same terms as Series A and the Series D preferred stock has substantially the same terms as Series C.

On February 14, 2000, EOG's Board of Directors declared a dividend of one preferred share purchase right (a "Right" or "Rights Agreement") for each outstanding share of common stock, par value $.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. 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 $.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 15% 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. The Board of Directors may reduce the threshold at which a person or a group becomes an Acquiring Person from 15% to not less than 10% of the outstanding common stock.

If a person or group becomes an Acquiring Person, all holders of Rights except the Acquiring Person may, for $90, purchase shares of our 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 $.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 $.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.

4. Transactions with Enron Corp. and Related Parties

Share Exchange. On August 16, 1999, EOG and Enron Corp. completed the Share Exchange whereby EOG received 62,270,000 shares of EOG's common stock out of 82,270,000 shares owned by Enron Corp. in exchange for all the stock of EOG's subsidiary, EOGI-India, Inc. Prior to the Share Exchange, EOG made an indirect capital contribution of approximately $600 million in cash, plus certain intercompany receivables, to EOGI-India, Inc. At the time of completion of this transaction, this subsidiary owned, through subsidiaries, all of EOG's assets and operations in India and China. EOG recognized a $575 million tax-free gain on the Share Exchange based on the fair value of the shares received, net of transaction fees of $14 million. Immediately following the Share Exchange, EOG retired the 62,270,000 shares of EOG's common stock received in the transaction. The weighted average basis in the treasury shares retired was first deducted from and fully eliminated existing additional paid in capital with the remaining value deducted from retained earnings. This transaction is a tax-free exchange to EOG. On August 30, 1999, EOG changed its corporate name to "EOG Resources, Inc." from "Enron Oil & Gas Company" and has since made similar changes to its subsidiaries' names.

Immediately prior to the closing of the Share Exchange, Enron Corp. owned 82,270,000 shares of EOG's common stock, representing approximately 53.5 percent of all of the shares of EOG's common stock that were issued and outstanding. As a result of the closing of the Share Exchange, the sale by Enron Corp. of 8,500,000 shares of EOG's common stock as a selling stockholder in the public offering referred to above, and the completion on August 17, 1999 and August 20, 1999 of the offering of Enron Corp. notes mandatorily exchangeable at maturity into up to 11,500,000 shares of EOG's common stock, Enron Corp.'s maximum remaining interest in EOG after the automatic conversion of its notes on July 31, 2002, will be under two percent (assuming the notes are exchanged for less than the 11,500,000 shares of EOG's common stock).

Effective as of August 16, 1999, the closing date of the Share Exchange, the members of the board of directors of EOG who were officers or directors of Enron Corp. resigned their positions as directors of EOG.

Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues. Prior to the Share Exchange, Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues included revenues from and associated costs paid to various subsidiaries and affiliates of Enron Corp. pursuant to contracts which, in the opinion of management, were no less favorable than could be obtained from third parties. Revenues from sales to Enron Corp. and its affiliates totaled $57.3 million in 1999 prior to the Share Exchange and $72.2 million in 1998. Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues also included certain commodity price swap and NYMEX-related commodity transactions with Enron Corp. affiliated companies, which in the opinion of management, were no less favorable than could be received from third parties. (See Note 12 "Price and Interest Rate Risk Management").

General and Administrative Expenses. Prior to the Share Exchange, EOG was charged by Enron Corp. for all direct costs associated with its operations. Such direct charges, excluding benefit plan charges (See Note 6 "Employee Benefit Plans"), totaled $10.6 million and $14.2 million for the years ended December 31, 1999 and 1998, respectively. Additionally, certain administrative costs not directly charged to any Enron Corp. operations or business segments were allocated to the entities of the consolidated group. Approximately $3.4 million and $5.1 million was incurred by EOG for indirect general and administrative expenses for 1999 and 1998, respectively. Management believes that these charges were reasonable.

Sale of Enron Corp. Options. In December 1997, EOG and Enron Corp. entered into an Equity Participation and Business Opportunity Agreement. Under the agreement, among other things, Enron Corp. granted EOG options to purchase 3.2 million shares of Enron Corp. During 1999, EOG sold the 3.2 million options and recognized a pre-tax gain of $59.6 million. The gain on sale of the options is included in other income (expense) - other, net in the consolidated statements of income and comprehensive income.

5. Income Taxes

The principal components of EOG's net deferred income tax liability at December 31, 2000 and 1999 were as follows:

(In thousands)	**2000**	1999
Deferred Income Tax Assets		
Non-Producing		
Leasehold Costs	**$ 22,623**	$ 25,199
Seismic Costs		
Capitalized for Tax	**15,536**	9,912
Alternative Minimum		
Tax Credit Carryforward	**–**	21,772
Trading Activity	**4,420**	1,426
Section 29 Credit		
Monetization	**12,774**	15,657
Other	**16,743**	13,993
Total Deferred Income		
Tax Assets	**72,096**	87,959
Deferred Income Tax Liabilities		
Oil and Gas Exploration		
and Development		
Costs Deducted for		
Tax Over Book Depreciation,		
Depletion and Amortization	**403,808**	299,704
Capitalized Interest	**5,697**	11,986
Other	**2,670**	2,221
Total Deferred Income		
Tax Liabilities	**412,175**	313,911
Net Deferred		
Income Tax Liability	**$ 340,079**	$ 225,952

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

(In thousands)	**2000**	1999	1998
United States	**$ 491,417**	$ 561,841	$ (3,297)
Foreign	**142,140**	5,871	63,579
Total	**$ 633,557**	$ 567,712	$ 60,282

Total income tax provision (benefit) was as follows:

(In thousands)	2000	1999	1998
Current:			
Federal	$ 81,912	$ 5,510	$ 10,496
State	7,528	3,234	1,474
Foreign	49,457	16,126	18,935
Total	138,897	24,870	30,905
Deferred:			
Federal	78,833	(49,474)	(31,279)
State	10,324	(502)	(4,589)
Foreign	8,572	23,724	9,074
Total	97,729	(26,252)	(26,794)
Income Tax Provision (Benefit)	$ 236,626	$ (1,382)	$ 4,111

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

	2000	1999	1998
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	1.83	0.31	(3.36)
Income Tax Related to Foreign Operations	1.32	1.60	4.76
Tight Gas Sand Federal Income Tax Credits	–	(1.45)	(17.36)
Revision of Prior Years' Tax Estimates	0.16	(0.21)	(10.78)
Share Exchange	–	(35.46)	–
Other	(.96)	(.03)	(1.45)
Effective Income Tax Rate	37.35%	(0.24)%	6.81%

EOG's foreign subsidiaries' undistributed earnings of approximately $380 million at December 31, 2000 are considered to be indefinitely invested outside the U.S. and, accordingly, no U.S. federal 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 U.S. income taxes, net of allowable foreign tax credits. Determination of any potential amount of unrecognized deferred income tax liabilities is not practicable.

In 2000, EOG fully utilized an alternative minimum tax credit carryforward of approximately $22 million to offset regular income taxes payable.

In 1999 and 2000, EOG entered into arrangements with a third party whereby certain Section 29 credits were sold by EOG to the third party, and payments for such credits will be received on an as-generated basis. As a result of these transactions, EOG recorded a deferred tax asset representing a tax gain on the sale of the Section 29 credit properties, which will reverse as the results of operations of such properties are recognized for book purposes.

6. Employee Benefit Plans

Employees of EOG were covered by various retirement, stock purchase and other benefit plans of Enron Corp. through August 1999. During each of the years ended December 31, 1999 and 1998, EOG was charged $4.4 million and $6.4 million, respectively, for all such benefits, including pension expense totaling $0.9 million and $1.3 million, respectively, by Enron Corp.

Pension and Postretirement Plans. Since August 1999, EOG has adopted defined contribution pension plans for most of its employees in the United States. EOG's contributions to these plans are based on various percentages of compensation, and in some instances, are based upon the amount of the employees' contributions to the plan. From August 31, 1999 to December 31, 1999 the cost of these plans amounted to approximately $1.2 million. For 2000, the cost of these plans amounted to approximately $3.1 million.

EOG also has in effect pension and savings plans related to its Canadian and Trinidadian subsidiaries. Activity related to these plans is not material relative to EOG's operations.

During 2000, EOG adopted postretirement medical and dental benefits 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. As of December 31, 2000, the postretirement plan had a benefit obligation of $1.5 million and during 2000, EOG recognized a $0.3 million net periodic benefit cost related to this plan.

Stock Plans.

Stock Options. EOG has various stock plans ("the Plans") under which employees of EOG and its subsidiaries and non-employee members of the Board of Directors 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 over a period of time based on the nature of the grants and as defined in the individual grant agreements. Terms for stock options granted under the Plans have not exceeded a maximum term of 10 years.

EOG accounts for the stock options under the provisions and related interpretations of Accounting Principles Board Opinion No. 25 ("APB 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 No. 25 for purposes of determining net income and to present the pro forma disclosures required by SFAS No. 123.

The following table sets forth the option transactions under the Plans for the years ended December 31:

(Options in thousands)	2000 Options	2000 Average Grant Price	1999 Options	1999 Average Grant Price	1998 Options	1998 Average Grant Price
Outstanding at January 1	**12,667**	**$ 18.66**	15,036	$ 18.35	9,735	$ 19.99
Granted	**1,317**	**30.88**	1,280	19.88	5,949	15.76
Exercised	**(6,726)**	**18.90**	(822)	16.22	(172)	15.14
Forfeited	**(202)**	**19.09**	(2,827)	18.26	(476)	20.62
Outstanding at December 31	**7,056**	**20.70**	12,667	18.66	15,036	18.35
Options Exercisable at December 31	**3,845**	**19.83**	8,118	19.23	7,703	19.38
Options Available for Future Grant	**6,387**		5,564		3,098	
Average Fair Value of Options Granted During Year	**$ 12.20**		$ 7.43		$ 4.75	

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 2000, 1999, and 1998, respectively: (1) dividend yield of 0.6%, 0.6% and 0.6%, (2) expected volatility of 30%, 28%, and 26%, (3) risk-free interest rate of 6.0%, 5.9%, and 5.1%, and (4) expected life of 6.0 years, 6.0 years and 4.9 years.

The following table summarizes certain information for the options outstanding at December 31, 2000 (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
$ 9.00 to $12.99	**24**	**1**	**$ 9.45**	**24**	**$ 9.45**
13.00 to 17.99	**2,137**	**8**	**14.72**	**979**	**15.24**
18.00 to 22.99	**3,271**	**6**	**20.09**	**2,161**	**20.02**
23.00 to 28.99	**560**	**5**	**23.93**	**505**	**23.74**
29.00 to 39.99	**1,047**	**10**	**32.93**	**173**	**32.84**
40.00 to 50.00	**17**	**10**	**47.11**	**3**	**47.11**
	7,056	**7**	**20.70**	**3,845**	**19.83**

EOG's pro forma net income and net income per share of common stock for 2000, 1999 and 1998, had compensation costs been recorded in accordance with SFAS No. 123, are presented below:

(In millions except per share data)	2000 As Reported	2000 Pro Forma	1999 As Reported	1999 Pro Forma	1998 As Reported	1998 Pro Forma
Net Income Available to Common	**$ 385.9**	**$ 373.4**	$ 568.6	$ 565.7	$ 56.2	$ 47.3
Net Income per Share Available to Common						
Basic	**$ 3.30**	**$ 3.19**	$ 4.04	$ 4.02	$ .36	$ .31
Diluted	**$ 3.24**	**$ 3.14**	$ 4.01	$ 3.99	$ .36	$ .31

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.

The Black-Scholes model used by EOG to calculate option values, as well as other currently accepted option valuation models, were developed to estimate the fair value of freely tradable, fully transferable options without vesting and/or trading restrictions, which significantly differ from EOG's stock option awards. These models also require highly subjective assumptions, including future stock price volatility and expected time until exercise, which significantly affect the calculated values. Accordingly, management does not believe that this model provides a reliable single measure of the fair value of EOG's stock option awards.

Restricted Stock and Units. Under the Plans, participants may be granted restricted stock and/or units without cost to the participant. The shares and units granted vest to the participant at various times ranging from one to seven years. Upon vesting, the restricted shares are released to the participants and the restricted units released to the participants are converted into one share of common stock. The following summarizes shares of restricted stock and units granted:

	2000	1999	1998
Outstanding at January 1	**265,168**	345,334	284,000
Granted	**200,566**	23,000	108,500
Released to Participants	**(171,502)**	(37,166)	(14,166)
Forfeited or Expired	**(2,661)**	(66,000)	(33,000)
Outstanding at December 31	**291,571**	265,168	345,334
Average Fair Value of Shares Granted During Year	**$ 16.10**	$ 21.43	$ 20.11

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 2000, 1999 and 1998 was approximately $1.3 million, $3.1 million and $1.5 million, respectively.

Treasury Shares. During 2000, 1999 and 1998, EOG purchased 6,709,138, 130,000, and 249,788 of its common shares, respectively, to offset the dilution resulting from shares issued under the EOG employee stock plans. The difference between the cost of the treasury shares and the exercise price of the options, net of federal income tax benefit of $41.3 million, $1.4 million and $.3 million for the years 2000, 1999 and 1998, 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 retained earnings thereafter.

7. Commitments and Contingencies

Letters Of Credit. At December 31, 2000 and 1999, EOG had letters of credit and guaranties outstanding totaling approximately $122 million and $118 million, respectively.

Contingencies. On July 21, 1999, two stockholders of EOG filed separate lawsuits purportedly on behalf of EOG against Enron Corp. and those individuals who were then directors of EOG, alleging that Enron Corp. and those directors breached their fiduciary duties of good faith and loyalty in approving the Share Exchange. The lawsuits seek to rescind the transaction or to receive monetary damages and costs and expenses, including reasonable attorneys' and experts' fees. EOG, Enron Corp. and the individual defendants believe the lawsuits are without merit and intend to vigorously contest them.

EOG is engaged in arbitration hearings to settle a disagreement over the timing of the conversion of a 5% overriding royalty interest held by a third party in EOG's Trinidad SECC block to a 15% working interest. EOG does not expect the outcome to have a material adverse effect on EOG's financial position or results of operations.

There are various other suits and claims against EOG that have arisen in the ordinary course of business. However, management does not believe 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. EOG has been named as a potentially responsible party in certain Comprehensive Environmental Response Compensation and Liability Act proceedings. However, management does not believe that any potential assessments resulting from such proceedings will individually or in the aggregate have a materially adverse effect on the financial condition or results of operations of EOG.

8. Net Income Per Share Available to Common

The following table sets forth the computation of basic and diluted earnings from net income available to common for the years ended December 31:

(In thousands, except per share amounts)	2000	1999	1998
Numerator for basic and diluted earnings per share - Net income available to common	$ 385,903	$ 568,559	$ 56,171
Denominator for basic earnings per share - Weighted average shares	116,934	140,648	154,002
Potential dilutive common shares -			
Stock options	2,038	964	461
Restricted stock and units	130	15	110
Denominator for diluted earnings per share - Adjusted weighted average shares	119,102	141,627	154,573
Net income per share of common stock			
Basic	$ 3.30	$ 4.04	$ 0.36
Diluted	$ 3.24	$ 4.01	$ 0.36

9. Supplemental Cash Flow Information

On August 16, 1999, EOG and Enron Corp. completed the Share Exchange whereby EOG received 62,270,000 shares of EOG's common stock out of 82,270,000 shares owned by Enron Corp. in exchange for all the stock of EOG's subsidiary, EOGI-India, Inc (see Note 4 "Transactions with Enron Corp. and Related Parties"). Prior to the Share Exchange, EOG made an indirect capital contribution of approximately $600 million in cash, plus certain intercompany receivables, to EOGI-India, Inc. At the time of completion of this transaction, EOG's net investment in EOGI-India, Inc. was $870 million.

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

(In thousands)	2000	1999	1998
Interest (net of amount capitalized)	$ 61,679	$ 67,965	$ 51,166
Income taxes	87,285	19,810	38,551

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 group is the Executive Committee, which consists of 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 U.S. 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	India[1]	Other[2]	Total
2000						
Net Operating Revenues	**$1,223,315[3][4]**	**$ 184,092[3]**	**$ 82,430**	**$ –**	**$ 58**	**$1,489,895[3]**
Depreciation, Depletion and Amortization	**316,814**	**39,253**	**13,959**	**–**	**–**	**370,026**
Operating Income (Loss)	**552,091**	**103,229**	**41,974**	**–**	**(431)**	**696,863**
Interest Income	**522**	**2,186**	**915**	**–**	**214**	**3,837**
Other Income (Expense)	**(6,344)**	**302**	**31**	**–**	**(126)**	**(6,137)**
Interest Expense	**59,841**	**7,550**	**323**	**–**	**–**	**67,714**
Income Tax Provision (Benefit)	**181,506**	**31,159**	**24,076**	**–**	**(115)**	**236,626**
Additions to Oil and Gas Properties	**499,207**	**69,157**	**33,223**	**–**	**1,051**	**602,638**
Total Assets	**2,465,204**	**374,476**	**159,872**	**–**	**1,263**	**3,000,815**
1999						
Net Operating Revenues	$ 635,587[3][4]	$ 97,817[3]	$ 62,689	$ 53,897	$ (7,891)	$ 842,099[3]
Depreciation, Depletion and Amortization	371,606	29,826	12,787	7,223	38,435	459,877
Operating Income (Loss)	(7,714)	33,941	32,643	22,699	(63,381)	18,188
Interest Income	113	184	626	51	63	1,037
Other Income (Expense)	630,872	112	128	(992)	(19,814)	610,306
Interest Expense	64,875	7,215	323	–	–	72,413
Income Tax Provision (Benefit)	(4,200)	4,637	18,484	8,858	(29,161)	(1,382)
Additions to Oil and Gas Properties	292,970	63,783	7,361	23,281	9,055	396,450
Total Assets	2,118,843	344,465	145,186	–	2,299	2,610,793
1998						
Net Operating Revenues	$ 597,215[4]	$ 71,680	$ 66,967	$ 75,995	$ (3,605)	$ 808,252
Depreciation, Depletion and Amortization	265,738	25,972	12,867	8,456	2,073	315,106
Operating Income (Loss)	54,272	11,908	42,094	41,718	(36,331)	113,661
Interest Income	216	88	507	205	131	1,147
Other Expense	(559)	–	(150)	(1,761)	(3,477)	(5,947)
Interest Expense	53,773	6,558	859	100	–	61,290
Income Tax Provision (Benefit)	(6,214)	(1,112)	21,517	13,401	(23,481)	4,111
Additions to Oil and Gas Properties	539,978	48,898	19,214	46,479	25,951	680,520
Total Assets	2,238,969	277,861	131,964	289,596	79,705	3,018,095

(1) See Note 4 "Transactions with Enron Corp. and Related Parties."

(2) Other includes China operations in 1999 and 1998. See Note 4 "Transactions with Enron Corp. and Related Parties."

(3) Sales activities with a certain purchaser in the United States and Canada segments totaled approximately $183.2 million and $98.1 million of the consolidated Net Operating Revenues for 2000 and 1999, respectively.

(4) Net Operating Revenues for the United States segment are net of costs related to natural gas marketing activities of $49.0 million, $44.6 million and $83.1 million for 2000, 1999 and 1998, respectively.

11. Other Income (Expense), Net

Other income (expense) other, net for the year ended December 31, 1999, included the gain of $59.6 million on the sale of 3.2 million shares of Enron Corp. options granted to EOG under the 1997 Equity Participation and Business Opportunity Agreement with Enron Corp., and $19.4 million loss relating to anticipated costs of abandonment of certain international activities.

12. Price and Interest Rate Risk Management Activities

Periodically, EOG enters into certain trading and non-trading activities including NYMEX-related commodity market transactions and other contracts. The non-trading portions of these activities have been designated to hedge the impact of market price fluctuations on anticipated commodity delivery volumes or other contractual commitments.

Trading Activities. At December 31, 2000, EOG had outstanding swap contracts covering notional volumes of approximately 0.7 million barrels ("MMBbl") of crude oil and condensate for 2001. EOG elected not to designate these crude oil swap contracts as a hedge of its 2001 crude oil production, and accordingly, is accounting for these swap contracts under mark-to-market accounting. At December 31, 2000, the fair value of these swap contracts was $0.4 million. During 1999, EOG did not enter into derivative contracts that were accounted for as trading activities. Trading activities in 1998 included a revenue increase of $1.1 million related to the change in market value of natural gas price swap options exercisable by a counterparty and partially offsetting "buy" price swap positions.

Hedging Transactions. At December 31, 2000, EOG had closed positions covering notional volumes of approximately 4 trillion British thermal units of natural gas for each of the years 2001 through 2005. At December 31, 2000, the aggregate deferred revenue reduction for 2001, 2002 and thereafter was approximately $1.2 million, $1.0 million and $3.8 million, respectively, and is classified as "Other Assets." During 2000, natural gas and crude oil and condensate revenues included a $17 million loss related to closed hedge positions.

Interest Rate Swap Agreements and Foreign Currency Contracts. At December 31, 2000 and 1999, a subsidiary of EOG and EOG are parties to offsetting foreign currency and interest rate swap agreements with an aggregate notional principal amount of $210 million. Such swap agreements terminated in January 2001. In November 1998, EOG entered into two interest rate swap agreements having notional values of $100 million each. The agreements were entered into to hedge the base variable interest rates of EOG's commercial paper, uncommitted credit facilities and affiliated borrowings. These agreements terminated in November 2000.

The following table summarizes the estimated fair value of financial instruments and related transactions for non-trading activities at December 31, 2000 and 1999:

	2000		1999	
(In millions)	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-Term Debt(2)	**$ 859.0**	**$ 831.1**	$ 990.3	$ 933.0
NYMEX-Related Commodity Market Positions	**(5.6)**	**(5.6)**	(18.0)	(20.3)

(1) Estimated fair values have been determined by using available market data and valuation methodologies. Judgment is necessarily 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 "Long-Term Debt."

Credit Risk. While notional contract amounts are used to express the magnitude of 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 does not anticipate nonperformance by the other parties.

13. Concentration of Credit Risk

Substantially all of EOG's accounts receivable at December 31, 2000 and 1999 result from crude oil and natural gas 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 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. Historical credit losses incurred on receivables by EOG have been immaterial.

14. Accounting for Certain Long-Lived Assets

In 1999, as a result of the change to EOG's portfolio of assets brought about by the Share Exchange (see Note 4"Transactions with Enron Corp. and Related Parties"), EOG conducted a re-evaluation of its overall business. As a result of this re-evaluation, some of EOG's projects were no longer deemed central to its business. EOG recorded non-cash charges in connection with the impairment and/or EOG's decision to dispose of such projects of $133 million pre-tax ($89 million after-tax). In addition, EOG recorded charges of $15 million pre-tax ($10 million after-tax) pursuant to a change in EOG's strategy related to certain offshore operations in the second quarter and an impairment of various North America properties in the fourth quarter of 1999 to depreciation, depletion and amortization expense. In the United States operating segment, a pre-tax impairment charge of $85 million was recorded to depreciation, depletion and amortization expense. The carrying values for assets determined to be impaired were adjusted to estimated fair values based on projected future discounted net cash flows for such assets. In the Other operating segment, a pre-tax charge of $36 million was recorded to depreciation, depletion and amortization expense to fully write-off EOG's basis and a pre-tax charge of $19 million was recorded to other income (expense)--other, net for the estimated exit costs related to EOG's decision to dispose of certain international operations. Net loss for the Other operating segment operations for 1999, excluding these charges, was approximately $3 million.

15. New Accounting Pronouncement-- SFAS No. 133

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133--"Accounting for Derivative Instruments and Hedging Activities" effective for fiscal years beginning after June 15, 1999. In June 1999, the FASB issued SFAS No. 137, which delays the effective date of SFAS No. 133 for one year, to fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, which amends the accounting and reporting standards of SFAS No. 133 for certain derivative instruments and certain hedging activities. SFAS No. 133, as amended by SFAS No. 137 and No. 138, cannot be applied retroactively and must be applied to (a) derivative instruments and (b) certain derivative instruments embedded in hybrid contracts that were issued, acquired or substantively modified after a transition date to be selected by EOG of either December 31, 1997 or December 31, 1998.

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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the statements of income and requires a company to formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

EOG adopted SFAS No. 133, as amended by SFAS No. 137 and No. 138, on January 1, 2001 for the accounting periods which begin thereafter. The adoption of SFAS No. 133 did not have a material impact on EOG's financial statements.

Supplemental Information to Consolidated Financial Statements

(In Thousands Except Per Share Amounts Unless Otherwise Indicated)
(Unaudited Except for Results of Operations for Oil and Gas Producing Activities)

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 to existing reserve estimates 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 recompletion. 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.

As a result of the re-evaluation of EOG's portfolio of assets following the Share Exchange, on November 12, 1999 senior management proposed to the Board of Directors ("the Board") of EOG to defer the development of the Big Piney Madison deep Paleozoic formation methane reserves in Wyoming for the foreseeable future. The Board approved the recommendation. As a result, the 1.2 trillion cubic feet of methane reserves in the formation, which are located on acreage owned by EOG and held by production for the foreseeable future, and which were classified as proved undeveloped reserves at December 31, 1998, were removed as a revision during 1999. At December 31, 1998, these reserves represented approximately $100 million or 5% of EOG's Standardized Measure of Discounted Future Net Cash Flows as adjusted for the sale of the India and China reserves as a result of the Share Exchange. At December 31, 2000, EOG had no plan to develop these reserves for the foreseeable future.

Estimates of proved and proved developed reserves at December 31, 2000, 1999 and 1998 were based on studies performed by the engineering staff of EOG for reserves in the United States, Canada, Trinidad, India and China (See Note 4 to the Consolidated Financial Statements regarding operations transferred under the Share Exchange). Opinions by DeGolyer and MacNaughton ("D&M"), independent petroleum consultants, for the years ended December 31, 2000, 1999, and 1998 covered producing areas containing 49%, 52% and 39%, respectively, of proved reserves, excluding deep Paleozoic methane reserves in 1998 and 1997, 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. The deep Paleozoic methane reserves were covered by the opinion of D&M for the year ended December 31, 1995. 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, 2000 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

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, 2000, 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 and Proved Developed Reserve Summary

	United States	Canada	Trinidad	SUBTOTAL	India[2]	Other[3]	TOTAL
Natural Gas (Bcf)[1]							
Net proved reserves at December 31, 1997	2,784.8[4]	387.4	328.8	3,501.0	471.6	7.7	3,980.3
Revisions of previous estimates	(55.9)	(2.5)	4.7	(53.7)	32.3	(0.4)	(21.8)
Purchases in place	123.0	54.9	–	177.9	–	–	177.9
Extensions, discoveries and other additions	272.8	62.9	693.8	1,029.5	340.9	103.0	1,473.4
Sales in place	(37.5)	–	–	(37.5)	–	–	(37.5)
Production	(233.8)	(38.5)	(50.9)	(323.2)	(20.2)	–	(343.4)
Net proved reserves at December 31, 1998	2,853.4[4]	464.2	976.4	4,294.0	824.6	110.3	5,228.9
Revisions of previous estimates	(1,199.1)[5]	(1.3)	4.5	(1,195.9)	–	–	(1,195.9)
Purchases in place	108.5	34.0	–	142.5	–	–	142.5
Extensions, discoveries and other additions	208.2	69.8	51.0	329.0	–	–	329.0
Sales in place[2]	(70.9)	(1.4)	–	(72.3)	(807.9)	(110.3)	(990.5)
Production	(242.9)	(41.8)	(37.3)	(322.0)	(16.7)	–	(338.7)
Net proved reserves at December 31, 1999	1,657.2	523.5	994.6	3,175.3	–	–	3,175.3
Revisions of previous estimates	**47.2**	**6.4**	**(0.4)**	**53.2**	**–**	**–**	**53.2**
Purchases in place	**188.8**	**39.4**	**–**	**228.2**	**–**	**–**	**228.2**
Extensions, discoveries and other additions	**255.4**	**23.8**	**65.1**	**344.3**	**–**	**–**	**344.3**
Sales in place	**(84.2)**	**(0.1)**	**–**	**(84.3)**	**–**	**–**	**(84.3)**
Production	**(243.0)**	**(47.3)**	**(45.8)**	**(336.1)**	**–**	**–**	**(336.1)**
Net proved reserves at December 31, 2000	**1,821.4**	**545.7**	**1,013.5**	**3,380.6**	**–**	**–**	**3,380.6**

(Table continued on following page)

	United States	Canada	Trinidad	SUBTOTAL	India[2]	Other[3]	TOTAL
Liquids (MBbl)[6][7]							
Net proved reserves at December 31, 1997	31,649	9,006	6,901	47,556	30,095	–	77,651
Revisions of previous estimates	(152)	(504)	(1,049)	(1,705)	3,063	73	1,431
Purchases in place	3,104	–	–	3,104	–	–	3,104
Extensions, discoveries and other additions	9,396	448	11,429	21,273	11,501	1,089	33,863
Sales in place	(1,039)	–	–	(1,039)	–	–	(1,039)
Production	(6,131)	(1,358)	(1,077)	(8,566)	(1,874)	–	(10,440)
Net proved reserves at December 31, 1998	36,827	7,592	16,204	60,623	42,785	1,162	104,570
Revisions of previous estimates	5,085	117	(72)	5,130	–	–	5,130
Purchases in place	2,753	39	–	2,792	–	–	2,792
Extensions, discoveries and other additions	9,520	2,416	509	12,445	–	–	12,445
Sales in place[2]	(121)	(37)	–	(158)	(41,306)	(1,162)	(42,626)
Production	(6,217)	(1,231)	(878)	(8,326)	(1,479)	–	(9,805)
Net proved reserves at December 31, 1999	47,847	8,896	15,763	72,506	–	–	72,506
Revisions of previous estimates	**(1,951)**	**46**	**28**	**(1,877)**	**–**	**–**	**(1,877)**
Purchases in place	**3,948**	**–**	**–**	**3,948**	**–**	**–**	**3,948**
Extensions, discoveries and other additions	**12,433**	**404**	**738**	**13,575**	**–**	**–**	**13,575**
Sales in place	**(484)**	**(2,474)**	**–**	**(2,958)**	**–**	**–**	**(2,958)**
Production	**(9,780)**	**(1,055)**	**(957)**	**(11,792)**	**–**	**–**	**(11,792)**
Net proved reserves at December 31, 2000	**52,013**	**5,817**	**15,572**	**73,402**	**–**	**–**	**73,402**
Bcf Equivalent (Bcfe)[1]							
Net proved reserves at December 31, 1997	2,975.0[4]	441.3	370.2	3,786.5	652.0	7.7	4,446.2
Revisions of previous estimates	(57.0)	(5.5)	(1.7)	(64.2)	50.8	–	(13.4)
Purchases in place	141.6	54.9	–	196.5	–	–	196.5
Extensions, discoveries and other additions	329.2	65.6	762.4	1,157.2	409.9	109.5	1,676.6
Sales in place	(43.7)	–	–	(43.7)	–	–	(43.7)
Production	(270.6)	(46.6)	(57.3)	(374.5)	(31.4)	–	(405.9)
Net proved reserves at December 31, 1998	3,074.5[4]	509.7	1,073.6	4,657.8	1,081.3	117.2	5,856.3
Revisions of previous estimates	(1,168.8)[5]	(0.6)	4.1	(1,165.3)	–	–	(1,165.3)
Purchases in place	125.1	34.3	–	159.4	–	–	159.4
Extensions, discoveries and other additions	265.3	84.3	54.0	403.6	–	–	403.6
Sales in place[2]	(71.6)	(1.6)	–	(73.2)	(1,055.7)	(117.2)	(1,246.1)
Production	(280.2)	(49.2)	(42.5)	(371.9)	(25.6)	–	(397.5)
Net proved reserves at December 31, 1999	1,944.3	576.9	1,089.2	3,610.4	–	–	3,610.4
Revisions of previous estimates	**35.5**	**6.8**	**(0.2)**	**42.1**	**–**	**–**	**42.1**
Purchases in place	**212.5**	**39.4**	**–**	**251.9**	**–**	**–**	**251.9**
Extensions, discoveries and other additions	**330.0**	**26.2**	**69.5**	**425.7**	**–**	**–**	**425.7**
Sales in place	**(87.1)**	**(15.0)**	**–**	**(102.1)**	**–**	**–**	**(102.1)**
Production	**(301.7)**	**(53.7)**	**(51.6)**	**(407.0)**	**–**	**–**	**(407.0)**
Net proved reserves at December 31, 2000	**2,133.5**	**580.6**	**1,106.9**	**3,821.0**	**–**	**–**	**3,821.0**

(Table continued on following page)

	United States	Canada	Trinidad	SUBTOTAL	India[2]	TOTAL
Net proved developed reserves at						
Natural Gas (Bcf) [1]						
December 31, 1997	1,349.0	370.9	328.8	2,048.7	286.6	2,335.3
December 31, 1998	1,429.7	387.4	283.0	2,100.1	407.4	2,507.5
December 31, 1999	1,446.5	451.1	250.2	2,147.8	–	2,147.8
December 31, 2000	**1,498.6**	**479.4**	**207.0**	**2,185.0**	**–**	**2,185.0**
Liquids (MBbl) [6] [7]						
December 31, 1997	27,707	8,885	6,901	43,493	23,322	66,815
December 31, 1998	33,045	7,465	4,782	45,292	33,472	78,764
December 31, 1999	41,717	7,041	3,833	52,591	–	52,591
December 31, 2000	**42,132**	**5,695**	**2,967**	**50,794**	**–**	**50,794**
Bcf Equivalents						
December 31, 1997	1,515.3	424.2	370.2	2,309.7	426.5	2,736.2
December 31, 1998	1,628.0	432.1	311.7	2,371.8	608.2	2,980.0
December 31, 1999	1,696.8	493.3	273.2	2,463.3	–	2,463.3
December 31, 2000	**1,751.4**	**513.6**	**224.8**	**2,489.8**	**–**	**2,489.8**

(1) Billion cubic feet or billion cubic feet equivalent, as applicable.
(2) See Note 4 "Transactions with Enron Corp. and Related Parties."
(3) Other includes China operations only. See Note 4 "Transactions with Enron Corp. and Related Parties."
(4) Includes 1,180 Bcf of proved undeveloped methane reserves contained, along with high concentrations of carbon dioxide and other gases, in deep Paleozoic (Madison) formations in the Big Piney area of Wyoming.
(5) Includes reduction of the 1,180 Bcf of proved undeveloped methane reserves mentioned in (4) as a result of EOG's decision to defer the development of the Big Piney Madison deep Paleozoic formation methane reserves in Wyoming for the foreseeable future.
(6) Thousand barrels.
(7) Includes crude oil, condensate and natural gas liquids.

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, 2000 and 1999:

	2000	1999
Proved Properties	**$4,966,667**	$ 4,459,727
Unproved Properties	**156,061**	143,013
Total	**5,122,728**	4,602,740
Accumulated depreciation, depletion and amortization	**(2,597,721)**	(2,267,812)
Net capitalized costs	**$2,525,007**	$ 2,334,928

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."

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

Exploration costs include exploration expenses, additions to exploration wells including those in progress, and depreciation of support equipment used in exploration activities.

Development costs include additions to production facilities and equipment, additions to development wells including those in progress and depreciation of support equipment and related facilities used in development activities.

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	Other	SUBTOTAL	India[1]	China[1]	TOTAL
2000								
Acquisition Costs of Properties								
Unproved	**$ 45,456**	**$ 5,741**	**$ –**	**$ –**	**$ 51,197**	**$ –**	**$ –**	**$ 51,197**
Proved	**88,473**	**13,965**	**–**	**–**	**102,438**	**–**	**–**	**102,438**
Subtotal	**133,929**	**19,706**	**–**	**–**	**153,635**	**–**	**–**	**153,635**
Exploration Costs	**98,654**	**9,711**	**10,849**	**3,581**	**122,795**	**–**	**–**	**122,795**
Development Costs	**335,053**	**46,000**	**29,688**	**–**	**410,741**	**–**	**–**	**410,741**
Subtotal	**567,636**	**75,417**	**40,537**	**3,581**	**687,171**	**–**	**–**	**687,171**
Deferred Income Taxes	**18,744**	**3,685**	**–**	**–**	**22,429**	**–**	**–**	**22,429**
Total	**$586,380**	**$79,102**	**$40,537**	**$ 3,581**	**$709,600**	**$ –**	**$ –**	**$709,600**
1999								
Acquisition Costs of Properties								
Unproved	$ 18,964	$ 2,276	$ –	$ –	$ 21,240	$ –	$ –	$ 21,240
Proved	22,092	20,838	–	–	42,930	–	–	42,930
Subtotal	41,056	23,114	–	–	64,170	–	–	64,170
Exploration Costs	65,070	6,516	8,425	4,350	84,361	1,083	1,014	86,458
Development Costs	234,900	39,544	4,801	20	279,265	23,281	7,942	310,488
Subtotal	341,026	69,174	13,226	4,370	427,796	24,364	8,956	461,116
Deferred Income Taxes	–	–	–	–	–	–	–	–
Total	$341,026	$ 69,174	$ 13,226	$ 4,370	$427,796	$ 24,364	$ 8,956	$ 461,116
1998								
Acquisition Costs of Properties								
Unproved	$ 32,925	$ 3,545	$ –	$ –	$ 36,470	$ –	$ –	$ 36,470
Proved	198,006	12,896	–	–	210,902	–	–	210,902
Subtotal	230,931	16,441	–	–	247,372	–	–	247,372
Exploration Costs	82,248	12,375	15,217	24,183	134,023	1,278	1,282	136,583
Development Costs	290,673	27,578	6,024	10,206	334,481	46,479	4,296	385,256
Subtotal	603,852	56,394	21,241	34,389	715,876	47,757	5,578	769,211
Deferred Income Taxes	–	–	–	–	–	–	–	–
Total	$603,852	$ 56,394	$ 21,241	$ 34,389	$715,876	$ 47,757	$ 5,578	$ 769,211

(1) See Note 4 "Transactions with Enron Corp. and Related Parties."

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	SUBTOTAL	India[2]	Other[3]	TOTAL
2000							
Operating Revenues							
Trade	**$1,118,434**	**$184,386**	**$ 82,430**	**$1,385,250**	**$ -**	**$ 59**	**$1,385,309**
Associated Companies	**102,834**	**-**	**-**	**102,834**	**-**	**-**	**102,834**
Gains (Losses) on Sales of Reserves and Related Assets	**5,833**	**(294)**	**-**	**5,539**	**-**	**-**	**5,539**
Total	**1,227,101**	**184,092**	**82,430**	**1,493,623**	**-**	**59**	**1,493,682**
Exploration Expenses, including Dry Hole	**72,000**	**4,881**	**7,314**	**84,195**	**-**	**337**	**84,532**
Production Costs	**172,464**	**31,785**	**15,669**	**219,918**	**-**	**129**	**220,047**
Impairment of Unproved Oil and Gas Properties	**33,647**	**2,070**	**-**	**35,717**	**-**	**-**	**35,717**
Depreciation, Depletion and Amortization	**315,746**	**39,253**	**13,959**	**368,958**	**-**	**2**	**368,960**
Income (Loss) before Income Taxes	**633,244**	**106,103**	**45,488**	**784,835**	**-**	**(409)**	**784,426**
Income Tax Provision (Benefit)	**231,182**	**41,274**	**25,018**	**297,474**	**-**	**(144)**	**297,330**
Results of Operations	**$ 402,062**	**$ 64,829**	**$ 20,470**	**$ 487,361**	**$ -**	**$ (265)**	**$ 487,096**
1999							
Operating Revenues							
Trade	$ 510,567	$ 86,581	$ 55,900	$ 653,048	$53,897	$ 39	$ 706,984
Associated Companies	125,204	11,161	-	136,365	-	-	136,365
Gains (Losses) on Sales of Reserves and Related Assets	2,254	75	-	2,329	-	(7,931)	(5,602)
Total	638,025	97,817	55,900	791,742	53,897	(7,892)	837,747
Exploration Expenses, including Dry Hole	49,181	5,122	5,865	60,168	1,083	3,415	64,666
Production Costs	114,810	24,698	8,322	147,830	13,413	2,334	163,577
Impairment of Unproved Oil and Gas Properties	29,384	2,224	-	31,608	-	-	31,608
Depreciation, Depletion and Amortization	370,536	29,826	12,787	413,149	7,223	38,436	458,808
Income (Loss) before Income Taxes	74,114	35,947	28,926	138,987	32,178	(52,077)	119,088
Income Tax Provision (Benefit)	21,283	12,259	15,909	49,451	15,445	(18,227)	46,669
Results of Operations	$ 52,831	$ 23,688	$ 13,017	$ 89,536	$16,733	$(33,850)	$ 72,419
1998							
Operating Revenues							
Trade	$ 448,653	$ 56,543	$ 66,967	$ 572,163	$75,995	$ 52	$ 648,210
Associated Companies	121,112	15,132	-	136,244	-	-	136,244
Gains (Losses) on Sales of Reserves and Related Assets	29,268	(15)	-	29,253	-	(3,658)	25,595
Total	599,033	71,660	66,967	737,660	75,995	(3,606)	810,049
Exploration Expenses, including Dry Hole	63,875	7,496	2,027	73,398	1,278	14,015	88,691
Production Costs	119,012	22,773	7,361	149,146	16,786	3,666	169,598
Impairment of Unproved Oil and Gas Properties	29,952	2,124	-	32,076	-	-	32,076
Depreciation, Depletion and Amortization	264,927	25,972	12,867	303,766	8,456	2,073	314,295
Income (Loss) before Income Taxes	121,267	13,295	44,712	179,274	49,475	(23,360)	205,389
Income Tax Provision (Benefit)	22,944	3,840	24,592	51,376	23,748	(7,370)	67,754
Results of Operations	$ 98,323	$ 9,455	$ 20,120	$ 127,898	$25,727	$(15,990)	$ 137,635

(1) Excludes net revenues associated with other marketing activities, interest charges, general corporate expenses and certain gathering and handling fees for each of the three years in the period ended December 31, 2000. The gathering and handling fees and other marketing net revenues are directly associated with oil and gas operations with regard to segment reporting as defined in SFAS No. 131--"Disclosures about Segments of an Enterprise and Related Information," but are not part of Disclosures about Oil and Gas Producing Activities as defined in SFAS No. 69.

(2) See Note 4 "Transactions with Enron Corp. and Related Parties."

(3) Other includes China (in 1999 and 1998) and other international operations. See Note 4 "Transactions with Enron Corp. and Related Parties."

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	SUBTOTAL	India[1]	Other[2]	TOTAL
2000							
Future cash inflows	**$18,500,822**	**$4,704,243**	**$1,860,366**	**$25,065,431**	**$ –**	**$ –**	**$25,065,431**
Future production costs	**(2,766,579)**	**(389,819)**	**(668,549)**	**(3,824,947)**	**–**	**–**	**(3,824,947)**
Future development costs	**(279,407)**	**(44,011)**	**(194,741)**	**(518,159)**	**–**	**–**	**(518,159)**
Future net cash flows before income taxes	**15,454,836**	**4,270,413**	**997,076**	**20,722,325**	**–**	**–**	**20,722,325**
Future income taxes	**(5,074,986)**	**(1,451,776)**	**(230,712)**	**(6,757,474)**	**–**	**–**	**(6,757,474)**
Future net cash flows	**10,379,850**	**2,818,637**	**766,364**	**13,964,851**	**–**	**–**	**13,964,851**
Discount to present value at 10% annual rate	**(4,368,717)**	**(1,304,886)**	**(377,811)**	**(6,051,414)**	**–**	**–**	**(6,051,414)**
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves[3]	**$ 6,011,133**	**$1,513,751**	**$ 388,553**	**$ 7,913,437**	**$ –**	**$ –**	**$ 7,913,437**
1999							
Future cash inflows	$ 4,653,014	$1,159,024	$1,455,951	$ 7,267,989	$ –	$ –	$ 7,267,989
Future production costs	(1,277,485)	(300,332)	(486,902)	(2,064,719)	–	–	(2,064,719)
Future development costs	(175,039)	(46,966)	(158,778)	(380,783)	–	–	(380,783)
Future net cash flows before income taxes	3,200,490	811,726	810,271	4,822,487	–	–	4,822,487
Future income taxes	(630,876)	(226,118)	(253,373)	(1,110,367)	–	–	(1,110,367)
Future net cash flows	2,569,614	585,608	556,898	3,712,120	–	–	3,712,120
Discount to present value at 10% annual rate	(842,382)	(207,717)	(267,965)	(1,318,064)	–	–	(1,318,064)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,727,232	$ 377,891	$ 288,933	$ 2,394,056	$ –	$	$ 2,394,056
1998							
Future cash inflows	$ 5,471,121	$ 827,416	$1,210,060	$ 7,508,597	$ 2,384,459	$ 179,329	$10,072,385
Future production costs	(1,280,875)	(200,492)	(347,431)	(1,828,798)	(556,609)	(127,039)	(2,512,446)
Future development costs	(316,175)	(38,963)	(161,424)	(516,562)	(392,546)	(11,325)	(920,433)
Future net cash flows before income taxes	3,874,071	587,961	701,205	5,163,237	1,435,304	40,965	6,639,506
Future income taxes	(903,983)	(119,655)	(229,281)	(1,252,919)	(614,297)	(7,111)	(1,874,327)
Future net cash flows	2,970,088	468,306	471,924	3,910,318	821,007	33,854	4,765,179
Discount to present value at 10% annual rate	(1,399,541)	(161,988)	(234,129)	(1,795,658)	(434,714)	(13,893)	(2,244,265)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,570,547	$ 306,318	$ 237,795	$ 2,114,660	$ 386,293	$ 19,961	$ 2,520,914

(1) See Note 4 "Transactions with Enron Corp. and Related Parties."

(2) Other includes China operations only. See Note 4 "Transactions with Enron Corp. and Related Parties."

(3) Natural gas prices have declined significantly since December 31, 2000; consequently, the discounted future net cash flows would be significantly reduced if the standardized measure was calculated in the first quarter of 2001.

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, 2000.

	United States	Canada	Trinidad	SUBTOTAL	India[1]	Other[2]	TOTAL
December 31, 1997	$ 1,549,719[3]	$ 277,312	$ 147,919	$ 1,974,950	$ 319,728	$ 5,776	$ 2,300,454
Sales and transfers of oil and gas produced, net of production costs	(423,733)	(48,902)	(59,606)	(532,241)	(59,209)	3,664	(587,786)
Net changes in prices and production costs	(33,809)	10,445	(36,730)	(60,094)	(103,097)	(6,961)	(170,152)
Extensions, discoveries, additions and improved recovery net of related costs	325,308	43,686	159,497	528,491	218,168	18,894	765,553
Development costs incurred	59,600	2,900	6,000	68,500	43,400	4,300	116,200
Revisions of estimated development costs	(26,611)	3,584	(11,410)	(34,437)	(66,128)	(3,233)	(103,798)
Revisions of previous quantity estimates	(35,216)	(4,109)	(1,142)	(40,467)	36,877	--	(3,590)
Accretion of discount	174,102	30,332	28,791	233,225	53,296	562	287,083
Net change in income taxes	47,745	(5,822)	(122)	41,801	212	(428)	41,585
Purchases of reserves in place	156,818	20,131	–	176,949	–	–	176,949
Sales of reserves in place	(33,549)	--	–	(33,549)	–	–	(33,549)
Changes in timing and other	(189,827)	(23,239)	4,598	(208,468)	(56,954)	(2,613)	(268,035)
December 31, 1998	1,570,547[3]	306,318	237,795	2,114,660	386,293	19,961	2,520,914
Sales and transfers of oil and gas produced, net of production costs	(520,961)	(73,044)	(47,578)	(641,583)	(40,484)	2,334	(679,733)
Net changes in prices and production costs	265,946	77,195	76,381	419,522	–	–	419,522
Extensions, discoveries, additions and improved recovery net of related costs	310,470	68,396	8,523	387,389	–	–	387,389
Development costs incurred	42,500	16,100	–	58,600	23,820	8,010	90,430
Revisions of estimated development costs	133,741	687	8,178	142,606	–	–	142,606
Revisions of previous quantity estimates	(163,423)[4]	(505)	2,051	(161,877)	–	–	(161,877)
Accretion of discount	171,588	33,815	37,790	243,193	–	–	243,193
Net change in income taxes	(27,883)	(79,397)	(22,874)	(130,154)	–	–	(130,154)
Purchases of reserves in place	102,086	18,769	–	120,855	–	–	120,855
Sales of reserves in place	(81,607)	(1,276)	–	(82,883)	(369,629)	(30,305)	(482,817)
Changes in timing and other	(75,772)	10,833	(11,333)	(76,272)	–	–	(76,272)
December 31, 1999	1,727,232	377,891	288,933	2,394,056	–	–	2,394,056
Sales and transfers of oil and gas produced, net of production costs	**(1,048,804)**	**(152,602)**	**(66,761)**	**(1,268,167)**	**–**	**–**	**(1,268,167)**
Net changes in prices and production costs	**5,459,629**	**1,850,021**	**153,961**	**7,463,611**	**–**	**–**	**7,463,611**
Extensions, discoveries, additions and improved recovery net of related costs	**1,502,377**	**94,379**	**20,544**	**1,617,300**	**–**	**–**	**1,617,300**
Development costs incurred	**77,000**	**24,100**	**29,600**	**130,700**	**–**	**–**	**130,700**
Revisions of estimated development costs	**(19,055)**	**39**	**(39,590)**	**(58,606)**	**–**	**–**	**(58,606)**
Revisions of previous quantity estimates	**153,862**	**30,376**	**(129)**	**184,109**	**–**	**–**	**184,109**
Accretion of discount	**190,045**	**48,912**	**45,192**	**284,149**	**–**	**–**	**284,149**
Net change in income taxes	**(2,436,834)**	**(606,556)**	**8,566**	**(3,034,824)**	**–**	**–**	**(3,034,824)**
Purchases of reserves in place	**671,604**	**136,138**	**–**	**807,742**	**–**	**–**	**807,742**
Sales of reserves in place	**(331,960)**	**(22,454)**	**–**	**(354,414)**	**–**	**–**	**(354,414)**
Changes in timing and other	**66,037**	**(266,493)**	**(51,763)**	**(252,219)**	**–**	**–**	**(252,219)**
December 31, 2000	**$ 6,011,133**	**$ 1,513,751**	**$ 388,553**	**$ 7,913,437**	**$ –**	**$ –**	**$ 7,913,437**

(1) See Note 4 "Transactions with Enron Corp. and Related Parties."

(2) Other includes China operations only. See Note 4 "Transactions with Enron Corp. and Related Parties."

(3) Includes approximately $55,316 and $100,284 in 1997 and 1998, respectively, related to the reserves in the Big Piney deep Paleozoic formations.

(4) Includes reserves reduction of approximately $172,057, discounted before income taxes, related to the reserves in the Big Piney deep Paleozoic formations.

Unaudited Quarterly Financial Information

	Quarter Ended			
(In Thousands, Except Per Share Amounts)	March 31	June 30	Sept. 30	Dec. 31
2000				
Net Operating Revenues	$ 259,897	$ 322,725	$ 402,152	$ 505,121
Operating Income	$ 80,210	$ 139,235	$ 203,658	$ 273,760
Income before Income Taxes	$ 65,659	$ 124,417	$ 188,943	$ 254,538
Income Tax Provision	24,169	46,900	72,466	93,091
Net Income	41,490	77,517	116,477	161,447
Preferred Stock Dividends	(2,654)	(2,860)	(2,755)	(2,759)
Net Income Available to Common	$ 38,836	$ 74,657	$ 113,722	$ 158,688
Net Income per Share Available to Common				
Basic(1)	$ 0.33	$ 0.64	$ 0.98	$ 1.36
Diluted(1)	$ 0.33	$ 0.63	$ 0.95	$ 1.33
Average Number of Common Shares				
Basic	117,827	116,666	116,559	116,684
Diluted	118,273	119,179	119,262	119,582
1999				
Net Operating Revenues	$ 169,561	$ 198,208	$ 236,887	$ 237,443
Operating Income (Loss)	$ (9,604)	$ 15,695	$ (53,229)	$ 65,326
Income before Income Taxes	$ 3,067	$ 32,273	$ 484,281	$ 48,091
Income Tax Provision (Benefit)	(1,999)	11,635	(28,640)	17,622
Net Income	5,066	20,638	512,921	30,469
Preferred Stock Dividends	-	-	-	(535)
Net Income Available to Common	$ 5,066	$ 20,638	$ 512,921	$ 29,934
Net Income per Share Available to Common				
Basic(1)	$ 0.03	$ 0.13	$ 3.75	$ 0.25
Diluted(1)	$ 0.03	$ 0.13	$ 3.71	$ 0.25
Average Number of Common Shares				
Basic	153,388	153,484	136,662	119,059
Diluted	154,048	154,540	138,271	119,778

(1) The sum of quarterly 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, 2000	1999	1998	1997	1996
Statement of Income Data:					
Net operating revenues	$1,489,895	$ 842,099	$ 808,252	$ 820,451	$ 767,813
Operating expenses					
Lease and well	140,915	132,233	137,932	133,014	113,783
Exploration costs	67,196	52,773	65,940	57,696	55,009
Dry hole costs	17,337	11,893	22,751	17,303	13,193
Impairment of unproved oil and gas properties	35,717	31,608	32,076	27,213	21,226
Depreciation, depletion and amortization	370,026	459,877(1)	315,106	278,179	251,278
General and administrative	66,932	82,857	69,010	54,415	56,405
Taxes other than income	94,909	52,670	51,776	59,856	48,089
Total	793,032	823,911	694,591	627,676	558,983
Operating income	696,863	18,188	113,661	192,775	208,830
Other income (expense), net	(2,300)	611,343(2)	(4,800)	(1,588)	(5,007)
Interest expense (net of interest capitalized)	61,006	61,819	48,579	27,717	12,861
Income before income taxes	633,557	567,712	60,282	163,470	190,962
Income tax provision (benefit)(3)	236,626	(1,382)	4,111(4)	41,500(5)	50,954
Net income	396,931	569,094	56,171	121,970	140,008
Preferred stock dividends	(11,028)	(535)	–	–	–
Net income available to common	$ 385,903	$ 568,559	$ 56,171	$ 121,970	$ 140,008
Net income per share available to common					
Basic	$ 3.30	$ 4.04	$ 0.36	$ 0.78	$ 0.88
Diluted	$ 3.24	$ 4.01	$ 0.36	$ 0.77	$ 0.87
Average number of common shares					
Basic	116,934	140,648	154,002	157,092	159,569
Diluted	119,102	141,627	154,573	157,663	160,708

(In Thousands)	At December 31, 2000	1999	1998	1997	1996
Balance Sheet Data:					
Oil and gas properties - net	$2,525,007	$ 2,334,928	$ 2,676,363	$ 2,387,207	$ 2,099,589
Total assets	3,000,815	2,610,793	3,018,095	2,723,355	2,458,353
Long-term debt					
Trade	859,000	990,306	942,779	548,775	466,089
Affiliate	–	–	200,000	192,500	–
Deferred revenue	–	–	4,198	39,918	56,383
Shareholders' equity	1,380,925	1,129,611	1,280,304	1,281,049	1,265,090

(1) Includes $133 million non-cash charges in connection with impairments and/or the Company's decision to dispose of projects no longer deemed central to its business.

(2) Includes a $575 million tax-free gain on the share exchange transactions (See Note 4 of Notes to Consolidated Financial Statements).

(3) Includes benefits of approximately $8 million, $12 million, $12 million and $16 million in 1999, 1998, 1997 and 1996 respectively, relating to tight gas sand federal income tax credits.

(4) Includes a benefit of $2 million related to the final audit assessments of India taxes for certain prior years, a benefit of $3.8 million related to reduced deferred franchise taxes, and $3.5 million related to cumulative Venezuela deferred tax benefits.

(5) Includes a benefit of $15 million primarily associated with the refiling of certain Canadian tax returns and the sale of certain international assets and subsidiaries.

(6) Includes a benefit of $9 million primarily associated with a reassessment of deferred tax requirements and the successful resolution on audit of Canadian income taxes for certain prior years.

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 cash dividends declared per share.

	Price Range		Cash
	High	Low	Dividends
1999			
First Quarter	$ 18.38	$ 15.69	$ 0.030
Second Quarter	21.50	16.00	0.030
Third Quarter	25.38	19.25	0.030
Fourth Quarter	23.00	14.38	0.030
2000			
First Quarter	**$ 24.06**	**$ 13.69**	**$ 0.030**
Second Quarter	**34.88**	**21.75**	**0.035**
Third Quarter	**40.88**	**26.69**	**0.035**
Fourth Quarter	**56.69**	**35.31**	**0.035**

As of March 12, 2001, there were approximately 380 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 33,630 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.

Officers and Directors

Fred C. Ackman[1]
Gonzales, Texas
Former Chairman,
President and CEO
The Superior Oil Company

George A. Alcorn[2]
Houston, Texas
President, Alcorn Exploration, Inc.

Mark G. Papa
Houston, Texas
Chairman and CEO
EOG Resources, Inc.

Edward Randall, III[3]
Houston, Texas
Investments

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

Donald F. Textor[4]
Locust Valley, New York
Former Partner/
Managing Director,
Goldman Sachs

Frank G. Wisner[5]
New York, New York
Vice Chairman
American International Group, Inc.
and Former U.S. Ambassador to
India, Philippines, Egypt & Zambia

Executive Committee

Mark G. Papa
Chairman and CEO

Edmund P. Segner, III
President and Chief of Staff

Loren M. Leiker
Executive Vice President,
Exploration and Development

Gary L. Thomas
Executive Vice President,
North America Operations

Barry Hunsaker, Jr.
Senior Vice President and General Counsel

Sandeep Bhakhri
Vice President and
Chief Information Officer

Officers (including key subsidiaries)

Lewis P. Chandler, Jr.
Senior Vice President, Law

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

William R. Thomas
Senior Vice President and
General Manager, Midland Division

William E. Albrecht
Vice President, Acquisitions
and Engineering

Maire A. Baldwin
Vice President, Investor Relations

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

Steven B. Coleman
Vice President and General Manager,
Oklahoma City Division

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

Phil C. DeLozier
Vice President, Business Development

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

Timothy K. Driggers
Vice President, Accounting and
Land Administration

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

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

Kevin S. Hanzel
Vice President, Audit

Andrew N. Hoyle
Vice President, Marketing and
Regulatory Affairs

John D. Huppler
Vice President and General Manager,
Tyler Division

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

David R. Looney
Vice President, Finance

Susan M. Murray
Vice President,
Government Affairs

Richard A. Ott
Vice President, Tax

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

Gary L. Smith
Vice President and General Manager,
Pittsburgh Division

Ann D. Janssen
Treasurer

(1) Chairman, Audit Committee; Member, Compensation and International Strategy Committees
(2) Member, Audit, Compensation, and International Strategy Committees
(3) Chairman, Compensation Committee; Member, Audit and International Strategy Committees
(4) Member, Compensation and International Strategy Committees
(5) Chairman, International Strategy Committee; Member, Compensation and Audit Committees

Glossary of Terms

Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bbls/d	Barrels per day
BOE	Barrels of oil equivalent
CEO	Chief Executive Officer
Division	Generic term for regional EOG office and/or subsidiary(ies)
$/Bbl	Dollars per barrel
$/Mcf	Dollars per thousand cubic feet
E&P	Exploration and production
LOE	Lease operating expense
MBbl	Thousand barrels
MBbls/d	Thousand barrels per day
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
Mcf/d	Thousand cubic feet per day
MMBbl	Million barrels
MMbtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
MMcf/d	Million cubic feet per day
MMcfe/d	Million cubic feet equivalent per day
SECC	South East Coast Consortium (Trinidad)
Tcf	Trillion cubic feet
Tcfe	Trillion cubic feet equivalent

Shareholder Information

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Website: www.eogresources.com

Common Stock Exchange Listing:

New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at
December 31, 2000: 116,904,292

Principal Transfer Agent

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Toll Free: (800) 519-3111
Outside U.S.: (201) 324-1225
Website: www.equiserve.com
Hearing Impaired: TDD (201) 222-4955

Additional Information

The Annual Meeting of Shareholders will be held at 2 p.m. CDT in the Granger "B" Ballroom of the Doubletree Hotel at Allen Center, 400 Dallas Street, Houston, Texas on Tuesday, May 8, 2001. 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 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 also can be accessed through the website.

Financial analysts and investors who need additional information should visit the EOG website at www.eogresources.com or contact Maire A. Baldwin, Investor Relations at (713) 651-6EOG.

eog resources

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