Energy Opportunity Growth

eog resources

1999 Annual Report

Contents

Highlights

- EOG Resources, Inc. reported 1999 net income available to common of $569 million, or $4.04 per share, compared to 1998 net income of $56 million, or $.36 per share.
- During the third quarter 1999, EOG Resources successfully completed the share exchange transfer of its India and China operations to Enron Corp. and realized a $575 million tax-free net gain from the transaction, which was partially offset by $95 million of after tax non-recurring charges.
- Continuing the company's focus on increasing return on capital, EOG Resources reduced the number of total shares outstanding in 1999 from 154 million to 119 million. This was accomplished through the share exchange transaction with Enron Corp. in which EOG Resources received 62 million shares of its common stock from Enron, and the issuance of 27 million shares of common stock in an equity offering during the third quarter.
- Reserve replacement for 1999 from all sources, including acquisitions and dispositions, was 136 percent. Reserve replacement from drilling activities alone was 109 percent.
- North American finding costs from all sources, including acquisitions and dispositions, were $.91 per Mcfe, a 28 percent decrease from 1998. U.S. finding costs were $1.02 per Mcfe, a 32 percent drop from 1998. Worldwide finding costs were $.84 per Mcfe.
- Recent property exchange transactions were completed with Burlington Resources and OXY USA Inc., that significantly add prospect inventory in the Oklahoma Panhandle, Permian Basin, East Texas and North Louisiana.
- During the first quarter 2000, EOG Resources, Inc. announced it had signed a 15-year natural gas supply contract for approximately 60 million cubic feet per day with the National Gas Company of Trinidad and Tobago Limited. The contract will supply a proposed 1,850 metric ton per day anhydrous ammonia plant to be constructed by Caribbean Nitrogen Company Limited.

Financial and Operating Highlights

	1999	1998	1997	1996	1995	1994
Net Operating Revenues, As Adjusted*	**$ 756**	$ 696	$ 748	$ 710	$ 633	$ 625
Income Before Interest and Taxes, As Adjusted*	**$ 147**	$ 81	$ 183	$ 204	$ 195	$ 165
Net Income Available to Common, As Adjusted*	**$ 58**	$ 43	$ 117	$ 140	$ 141	$ 147
Adjustments for India and China Operations and Certain Nonrecurring Items	**$ 511**	$ 13	$ 5	$ —	$ 1	$ 1
Net Income Available to Common, As Reported	**$ 569**	$ 56	$ 122	$ 140	$ 142	$ 148
Discretionary Cash Flow*	**$ 466**	$ 427	$ 492	$ 472	$ 419	$ 422
Exploration and Development Expenditures*	**$ 434**	$ 725	$ 627	$ 523	$ 497	$ 486
Wellhead Natural Gas Volumes (MMcf/d)*	**892**	915	871	830	743	749
Wellhead Natural Gas Prices ($/Mcf)*	**$ 1.94**	$ 1.74	$ 2.06	$ 1.78	$ 1.29	$ 1.62
Wellhead Crude Oil and Condensate Volumes (MBbls/d)*	**19.4**	19.6	17.6	16.8	16.6	12.5
Wellhead Crude Oil and Condensate Prices ($/Bbl)*	**$ 17.91**	$ 12.61	$ 19.21	$ 20.67	$ 16.78	$ 15.62
NYSE Price Range ($/Share)						
High	**$ 25.38**	$ 24.50	$ 27.00	$ 30.63	$ 25.38	$ 24.63
Low	**$ 14.38**	$ 11.75	$ 17.50	$ 22.38	$ 17.13	$ 17.38
Close	**$ 17.56**	$ 17.25	$ 21.19	$ 25.25	$ 24.00	$ 18.75
Cash Dividends Per Share	**$ .12**	$ .12	$ .12	$ .12	$ .12	$ .12
Average Shares Outstanding (Millions)	**140.9**	154.3	157.4	159.9	159.9	159.8
Year-end Shares Outstanding (Millions)	**119.1**	153.7	155.1	159.8	159.8	160.0

* Adjusted to exclude India and China operations and certain nonrecurring items.

EOG Resources, Inc., formerly Enron Oil & Gas Company, is one of the largest independent (non-integrated) oil and gas companies in the United States. EOG Resources' production base is heavily weighted toward natural gas in the U.S., Canada and offshore Trinidad.

1999 marked the end of one era and the start of a new one for our company. On August 16, 1999, we announced that we had successfully closed a share exchange agreement with Enron Corp. to establish a new independent identity.

We've adopted a new name, EOG Resources, Inc., and continue to trade on the New York Stock Exchange under the ticker symbol "EOG."

While our new independent status provided us with the ideal opportunity to re-evaluate our strategy, we remain on course with the precise direction we had previously charted. Our goal remains consistent: EOG Resources wants to be ranked the best independent exploration and production company in the industry. To meet this goal and continue to enhance shareholder value, we have rededicated ourselves to the fundamentals upon which our company was built. We also have reaffirmed that the discipline we have developed in running a leading exploration and production company will continue to position us for future growth.

Trends in the North American natural gas market will impact our success and we're monitoring developments closely. It is our thesis that the North American natural gas market is in the beginning stages of a tight multiyear supply and demand balance. Domestic natural gas production has declined for the past two years and Canadian production growth has been slower than expected. U.S. natural gas demand today stands at 22 Tcf. The Gas Research Institute estimates that total U.S. demand will grow to 30 Tcf in the next ten years, primarily driven by electric generation, residential and industrial applications. The North American E&P industry has a difficult challenge to supply this demand increase, and this should provide continued natural gas price strength.

EOG Resources is well positioned to take advantage of this projected supply-constrained environment;

• EOG Resources is natural gas focused. Consistent with our weighting of prior years, 87 percent of our 1999 production was natural gas. Also, 87 percent of our total production comes from North America.

• EOG Resources is a low cost producer. In a commodity industry like exploration and production, cost control is critical.

• EOG Resources is per share driven with operating efficiencies magnified in per share performance. As a result of share repurchases subsequent to yearend, we now have 117 million shares outstanding, down from 154 million prior to the share exchange transaction.

• EOG Resources is a consistent performer, demonstrated by delivering superior 5 percent production growth on a per share basis to shareholders in 1999.

• EOG Resources is rate of return driven and has consistently maintained a rate of return capital investment program that has consistently generated one of the highest net income to cash flow ratios in our peer group.

• The 775 employees who make up EOG Resources' motivated workforce thrive in our decen-

Mark G. Papa, Edmund P. Segner, III

tralized organization composed of seven North American divisions and one international division. All employees share in the company's success through our employee stock option program.

• We plan additional international expansion using the same successful template we developed for our Trinidad activities and India and China operations (which were transferred to Enron as part of the share exchange agreement).

• With our new independent identity, EOG Resources has the financial flexibility to consider larger acquisition opportunities. As always, new investments will be scrutinized carefully to ensure they are compatible with our operating strengths and company goals. Based upon current cash flow estimates, we expect to have free cash flow over and above our divisions' drilling requirements. This free cash flow will be available for property acquisitions, debt repayment or share repurchases.

The momentum at EOG Resources is exciting! We continue to believe that EOG Resources is extraordinarily well positioned to add significant value to our shareholders.

In closing, we would like to express our appreciation to Forrest E. Hoglund who served as chairman since 1988. He retired, as previously planned, from the company contemporaneously with the closing of the share exchange agreement. Our management and employees are most appreciative of Forrest's leadership and vision from the time of the initial public offering through more than a decade of significant company growth.

Mark G. Papa
Chairman and Chief Executive Officer

Edmund P. Segner, III
President and Chief of Staff

EOG Resources employees (left) Stephen Lipari, Corpus Christi Division Production Manager and (right) Willie Mason, Area Production Superintendent, check the Ottis facility in the Abbey's Point Field, Matagorda County, Texas.

energy

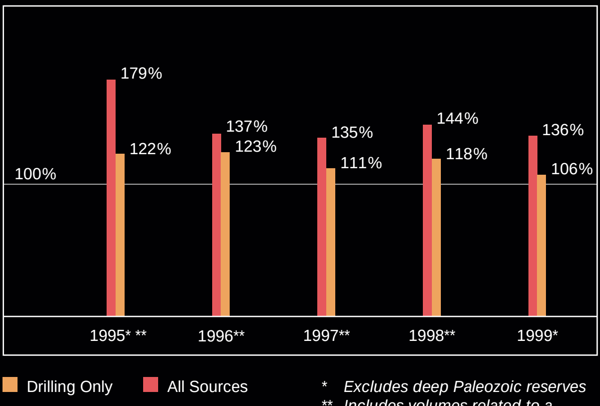
Despite the uncertainty that surrounded EOG Resources last year when prospective buyers were swarming around a hotel data room like bargain hunters at an auction, a remarkable phenomenon became apparent at the Houston headquarters and in every division office. Our employees never wavered, never lost their dedication or interest, and never gave up hope although they were unsure about their futures with the company.

They refused to lose the focus that could lead the company to the next discovery or the next deal. Our employees recognized that negotiations would ultimately resolve their fate and while they had no control over that bargaining process, they could continue to make a difference by doing their jobs well. So they did. In 1999, EOG Resources was the most active driller in the U.S.

In August, when the share exchange with Enron jelled and EOG Resources' future was solidified, employees were jubilant. They applauded and celebrated. Their determination was rewarded handsomely. Then they went back to work, harder than ever.

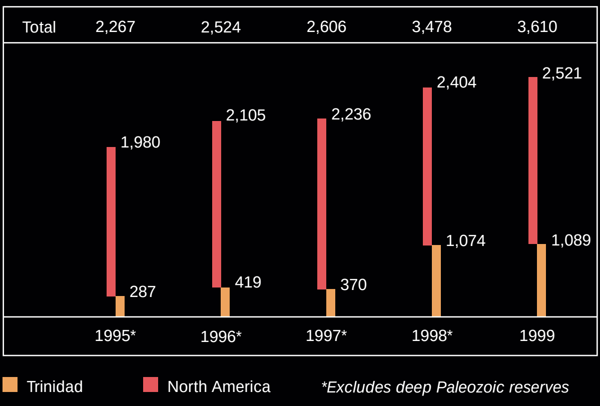
Today, EOG Resources employees are renewed, invigorated and stimulated. What does **Energy** feel like? Spend time around our 775 employees and you'll find out.

North American Reserve Replacement



* *Excludes deep Paleozoic reserves*
** *Includes volumes related to a volumetric production payment*

Year-End Reserves *(Bcfe)*



**Excludes deep Paleozoic reserves*

Denver, Colorado/Rockies Division

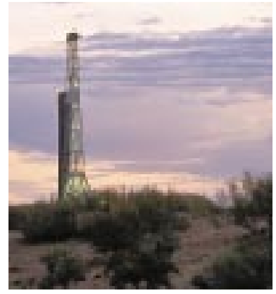
- 1999 Bcfe production: 63.4,
- Key producing areas: Big Piney – Labarge Platform, Vernal – Chapita/Natural Buttes and Cepo/Cedar Chest,
- Areas with upside potential: Cepo/Cedar Chest, Big Piney, Chapita/Natural Buttes and California - North Shafter.

Net crude oil and condensate production in the Denver Division increased from 3,000 Bbls/d to over 4,500 Bbls/d during a period when prices increased from $10 to over $30 per barrel, thus enhancing division and total company economics.

In the Washakie Basin, at a rate unusually high for the area, the Cepo Lewis 21-18 discovery flowed over 10 MMcf/d of natural gas and has produced over 1 Bcf since August 1999. There is potential for an additional five to 10 high rate wells in this area.

There also is potential for several additional high rate oil wells in the range of 1,000 Bbls/d in California's North Shafter Field. EOG Resources will have working interests ranging from 50 to 100 percent in these wells.

The company created and captured significant value for a majority of its California properties in a property exchange with OXY USA Inc. Completed at year-end 1999, the exchange secures large prospect inventories with significant underdeveloped properties in two operating divisions.



Midland, Texas Division

- 1999 Bcfe production: 40.5,
- Key producing areas: Morrow and Wolfcamp in Southeast New Mexico, Midland Basin and Val Verde Basin,
- Areas with upside potential: Southeast New Mexico and Midland Basin.

EOG Resources' Midland Division completed several significant wells in key producing areas. The Triste Draw "3" Fed. No. 1 in Lea County, New Mexico, in which the company has a 100 percent working interest, flowed 10 MMcf/d from the Wolfcamp formation. Another well, the Amtrack State Com. No. 1 in Eddy County, New Mexico, in which EOG Resources holds a 54 percent working interest, flowed 10 MMcf/d of natural gas and 100 Bbls/d of condensate from the Morrow formation. The Halff "18" No. 1 in Upton County, Texas, in which EOG Resources holds a 95 percent working interest, flowed 1,000 Bbls/d of crude oil and 900 Mcf/d of natural gas from the Wolfcamp carbonate.

In the southeast New Mexico area, 17 Wolfcamp wells were drilled in 1999 adding 19.5 Bcfe of net reserves for a 45 percent rate of return at finding costs of $0.62 per Mcfe.

During 1999, 18 wells were drilled in the Midland Basin adding 1.8 MMBbl of net crude oil reserves. They were drilled at an excellent rate of return with finding costs of $3.60 per BOE.

In a property trade with Burlington Resources during the first quarter of 2000, the Midland Division received oil and gas properties in southeast New Mexico and West Texas that will increase EOG Resources' reserves, production and undeveloped leasehold in the Permian Basin.

Bathed in the rich colors of sunrise, an offshore rig drills in EOG Resources' Modified U(a) Block off the southeast coast of Trinidad.

Opportunity

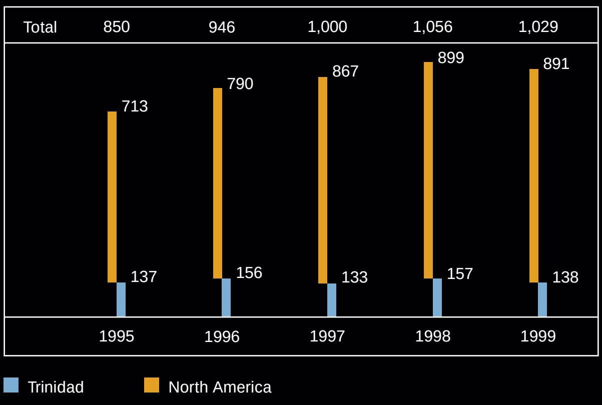
A well-worn adage states that there are three types of people in the world: *those who watch things happen, those who make things happen and those who don't know what happened.* The same description might apply to large companies where not all employees are in step, but no one really seems to notice.

At EOG Resources, our workforce has demonstrated over and over again that it is comprised of men and women *who make things happen.*

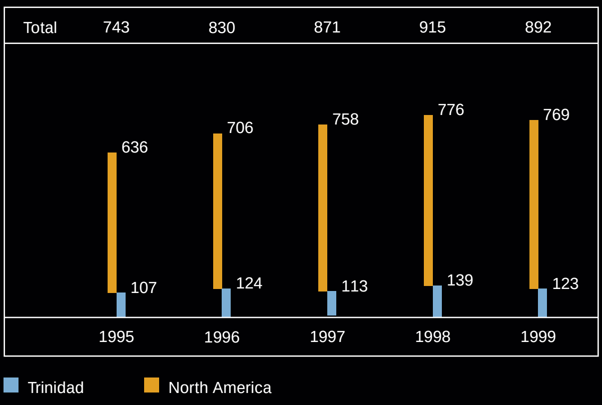
Here, a great deal of effort goes into providing employees with the tools they need and the motivation that inspires them to create our company's future. Further enhancing the entrepreneurial spirit is the fact that every employee is a shareholder.

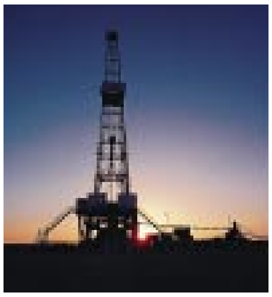
Our employees have the courage to challenge the status quo and are comfortable with the prospect of taking calculated risks. As a result, they are growing personally and as a team, savoring the satisfaction that development brings. How does EOG Resources define **Opportunity**? It's the word we think best describes what our employees envision every day when they come to work.

Total Production Volumes *(MMcfe/d)*



Natural Gas Volumes *(MMcf/d)*





Oklahoma City, Oklahoma Division

- 1999 Bcfe production: 27.8,
- Key producing areas: Oklahoma Panhandle and Anadarko Basin,
- Fields with upside potential: Hugoton Deep, Hemphill, Cruse and Sentinel.

In 1999, the Oklahoma City Division made a Texas County Toronto field discovery totalling 20 Bcf (net) that produced 20 MMcf/d of natural gas from 10 wells in which EOG Resources holds a 70 percent working interest. Also in Texas County, Oklahoma, the division obtained a 320,000 acre farm-in as a part of the OXY USA Inc. property exchange and also made an acquisition of 20,000 undeveloped acres in the area. EOG Resources controls over 400,000 acres in the Oklahoma Panhandle, an area where it has had excellent drilling results.

In Cimarron County, Oklahoma, the division drilled 10 wells adding 7 MMcf/d of natural gas in the Keyes Dome area. In the Mountain Front play, the Oklahoma City Division has an acreage position of 8,000 net acres with an average working interest of 30 percent.

Corpus Christi, Texas Division

- 1999 Bcfe production: 55.7,
- Key producing fields: Pok-A-Dot, Rosita, Black Creek, El Huerfano, Wadsworth, Big Boggy Creek and Abbey's Point,
- Areas with upside potential: Pok-A-Dot, Rosita and Wadsworth Field and Bay City area,
- Two new 1999 field discoveries were added at Abbey's Point and Big Boggy Creek in Matagorda County.

Utilizing newly acquired 3-D data in Webb County, the Corpus Christi Division added two significant field extensions in the Pok-A-Dot area. In 1999, 13 wells were drilled in the Slator Ranch and Marshall area adding net production of 28 MMcf/d of natural gas and 407 Bbls/d of condensate. For 2000, 33 wells are planned for a two to three-rig program with expansion into several new areas.

Significant play expansion is underway in the geo-pressured Frio where seven wells were drilled in 1999, adding 19.4 Bcfe. These wells are currently producing 55 MMcf/d of natural gas and 944 Bbls/d of condensate. Drilling on a 12-well program got underway January 30, 2000. At Abbey's Point Field, the Ottis No. 1 and Sutherland No. 1 together averaged net production of approximately 32 MMcf/d of natural gas and 480 Bbls/d of condensate. With new 3-D data for Bay City, a very active 2000 development program is planned.

EOG Resources' employees (left) Jimmy Nelson, pumper (right) Lee Hampton, head mechanic, and (background) Wayne Thompson, pumper, work at the Carthage Gas Unit Compressor Station in Panola County, Texas. Throughput at the 7,000 horsepower facility is 33 MMcf/d and 200 Bbls/d.

growth

Factors like competition, world market conditions and particularly the weather impact EOG Resources' stock price performance on a short-term basis. But we're bold enough to predict the future and we like what we see! Let us share our dream with you:

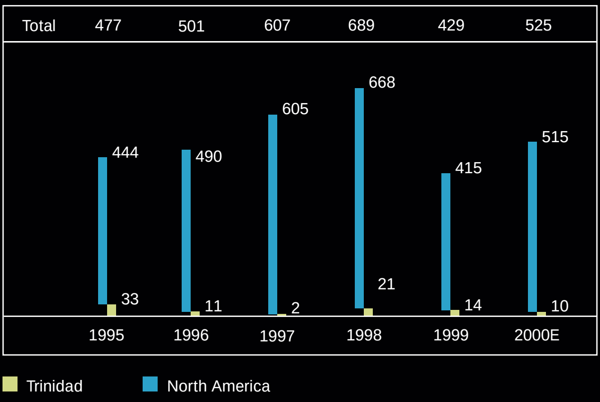
In five years, EOG Resources will be the recognized global independent leader in the delivery of crude oil and natural gas volumes and shareholder value.

Pretty lofty goal? Agreed. But we wouldn't say it if we didn't believe that it's a realistic goal. EOG Resources already has the basics in hand: our team of remarkably talented and dedicated employees and a carefully crafted gameplan. Let us tell you more.

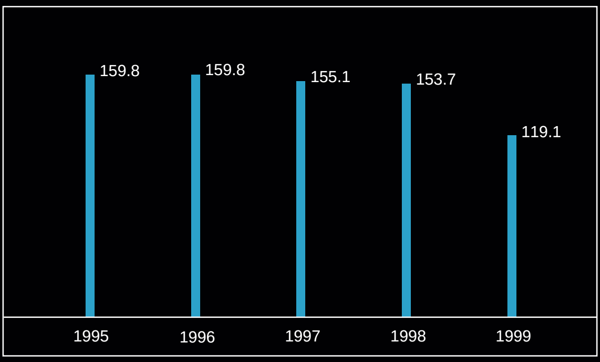
EOG Resources will continue its natural gas focus. Our portfolio will be balanced between exploration and exploitation and development. We'll pay close attention to short term results and long term growth. Our acquisition strategy will be aggressive. We'll maintain the decentralized structure that we've successfully built over the years and embrace technological change wherever it's advantageous. We'll consistently be the low cost operator and, we hope, the employer of choice in the entire oil and gas exploration and production industry.

For EOG Resources, **Growth** will culminate in the realization of our dream of leading our industry. Come along and monitor our progress toward achieving this goal!

Exploration & Development Expenditures *($ Millions)*



Year-end Shares Outstanding *(Millions)*



Offshore Division

- 1999 Bcfe production: 48.6,
- Key producing fields: Eugene Island 135 and Matagorda 622/623,
- Fields with upside potential: Eugene Island 135 continued delineation and exploration potential and Matagorda 622/623 additional development potential from reprocessed 3-D seismic data.

The Eugene Island 135 Field was successfully expanded with the completion of the Eugene Island 135 B-1 well. During 1999, the Offshore Division successfully reduced LOE by 19 percent from 1998 and is focusing on an active acquisition program targeting Gulf of Mexico shelf producing properties in 2000.

EOG Resources has been named a 1999 safety award finalist by the Minerals Management Service of the U.S. Department of the Interior in the outer continental shelf. EOG Resources earned this distinction by being one of five top operators in the "moderate or high activity" level with an outstanding safety and compliance record for drilling and production.

Tyler, Texas Division

- 1999 Bcfe production: 40.1,
- Key producing fields: Carthage, Stowell/Big Hill, North Milton,
- Fields with upside potential: Logansport, Carthage, West Milton, Stowell/Big Hill and Minden Dome.

During 1999, the Tyler Division increased production over 20 percent versus 1998, through a 53 well drilling program with a 90 percent success rate.

The division acquired OXY USA Inc.'s East Texas and northern Louisiana assets as part of a property exchange. Located adjacent to existing EOG Resources' properties, the OXY USA Inc. wells are currently producing 30 MMcf of natural gas per day and 2,700 Bbls/d of oil and condensate.

In Mississippi, several attractive Hosston oil wells were drilled, setting up 2000 drilling activity. The Tyler Division successfully drilled and economically completed two deep directional wells at North Milton field in East Texas.

Canada Division

- 1999 Bcfe production: 49.2,
- Key producing areas: Sandhills, Blackfoot and Grande Prairie,
- Areas with upside potential: Sandhills and Blackfoot.

Strategic property acquisitions have positioned the Canada Division to expand in both the Sandhills and Blackfoot areas. In its most active program ever, the Canada Division drilled 393 shallow gas wells in the Sandhills, Blackfoot and Smith Coulee areas in 1999, developing approximately 70 Bcf of natural gas reserves and adding an additional 20 Bcf of undeveloped natural gas reserves. In 2000, plans call for drilling at least another 350 shallow gas wells and several more exploitation and exploration wells.

In 1999, the Canada Division replaced 237 percent of production, including 171 percent from drilling alone at a finding cost of $.57 per Mcfe.

International Division

- 1999 Bcfe production (Trinidad): 50.1,
- Fields with upside potential: Kiskadee and Osprey.

In Trinidad, natural gas and liquids production remained strong last year with net production averaging 123 MMcf/d of natural gas and 2,400 Bbls/d of condensate from the SECC Block in which EOG Resources owns a 95 percent working interest.

To date, reserves of 675 Bcfe have been booked on the U(a) Block following the July 1998 Osprey discovery. The structure could ultimately contain 1 Tcfe of natural gas. EOG Resources owns a 100 percent working interest in this block.

In January 2000, EOG Resources finalized a 15-year contract to supply 60 MMcf/d of natural gas to the CNC Ammonia Plant to be built in Trinidad by late 2002. Approximately half of the proved reserves at Osprey are committed to the plant. EOG Resources took a lead role in developing this local natural gas market and also holds a 16 percent equity interest in the plant.

Three additional prospects with significant upside potential are drill-ready on the SECC and U(a) Blocks. Current net deliverability from SECC is in excess of 180 MMcf/d. Of that, 113 MMcf/d is committed to a take-or-pay contract with NGC.

EOG Resources is actively reviewing additional international opportunities to complement our strong North American activities.

The following review of operations for each of the three years in the period ended December 31, 1999 should be read in conjunction with the consolidated financial statements of EOG Resources, Inc. ("the Company") and notes thereto beginning with page 18.

Results of Operations

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

	Year Ended December 31,		
	1999	1998	1997
Natural Gas Volumes (MMcf per day)			
United States [1]	**654**	671	657
Canada	**115**	105	101
Trinidad	**123**	139	113
India [2]	**46**	56	18
Total	**938**	971	889
Average Natural Gas Prices ($/Mcf)			
United States [3]	**$ 2.12**	$ 1.93	$ 2.32
Canada	**1.80**	1.40	1.43
Trinidad	**1.08**	1.06	1.05
India [2]	**1.95**	2.41	2.79
Composite	**1.94**	1.78	2.07
Crude Oil and Condensate Volumes (MBbl per day)			
United Sates	**14.4**	14.0	11.7
Canada	**2.6**	2.6	2.5
Trinidad	**2.4**	3.0	3.4
India [2]	**4.1**	5.1	2.3
Total	**23.5**	24.7	19.9
Average Crude Oil and Condensate Prices ($/Bbl)			
United States	**$ 18.41**	$ 12.84	$ 19.81
Canada	**16.77**	11.82	17.16
Trinidad	**16.21**	12.26	18.68
India [2]	**12.80**	12.86	20.05
Composite	**17.03**	12.66	19.30
Natural Gas Equivalent Volumes (MMcfe per day) [4]			
United States	**757**	771	743
Canada	**134**	128	124
Trinidad	**138**	157	133
India [2]	**70**	86	32
Total	**1,099**	1,142	1,032
Total Bcfe Deliveries	**401**	417	377

(1) Includes 48 MMcf per day in 1998 and 1997 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 7 to the Consolidated Financial Statements.
(3) Includes an average equivalent wellhead value of $1.53 per Mcf in 1998 and $1.73 per Mcf in 1997 for the volumes detailed in note (1), net of transportation costs.
(4) Includes natural gas, crude oil, condensate and natural gas liquids.

1999 compared to 1998 During 1999, net operating revenues increased $31 million to $801 million. Total wellhead revenues of $823 million increased by $68 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 $55 million. Average wellhead crude oil and condensate prices were up by 35% increasing net operating revenues by $37 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 $21 million. The decrease in volumes is primarily due to the transfer of producing properties in the Share Exchange Agreement ("Share Exchange") and decreased deliveries in Trinidad. (See Note 7 to Consolidated Financial Statements for a discussion of the Share Exchange.) 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 $21 million during 1999, compared to a $4 million reduction in 1998.

1998 compared to 1997 During 1998, net operating revenues decreased $14 million to $769 million. Total wellhead revenues of $755 million decreased by $74 million, or 9%, as compared to 1997.

Average wellhead natural gas prices for 1998 were approximately 14% lower than the comparable period in 1997 reducing net operating revenues by approximately $104 million. Average wellhead crude oil and condensate prices were down by 34% worldwide decreasing net operating revenues by $60 million. Revenues from the sale of natural gas liquids decreased $6 million primarily due to lower wellhead prices. Wellhead natural gas volumes were approximately 9% higher than the comparable period in 1997 increasing net operating revenues by nearly $62 million. Natural gas production in India increased 38 MMcf per day from the Tapti and Panna fields, which did not commence deliveries until late in the second quarter of 1997 and the first quarter of 1998, respectively. Production in Trinidad increased 26 MMcf per day due primarily to additional volumes above the current contract level relating to gas balancing volumes pursuant to a field allocation agreement. North America wellhead natural gas production was approximately 2% higher than the comparable period in 1997. Wellhead crude oil and condensate volumes were 24% higher than in 1997 increasing net operating revenues by $34 million. Production from the Panna and Mukta fields in India more than doubled as a result of the ongoing development program and shut-down of crude oil production in the second quarter of 1997 to allow for the conversion from temporary to permanent production facilities. North America crude oil and condensate volumes increased 17% due primarily to higher levels of liquids production in South Texas and offshore.

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 decreased net operating revenue by $4 million during 1998, compared to a $61 million reduction in 1997, representing an improvement of $57 million.

Operating Expenses

1999 compared to 1998 During 1999, operating expenses of $783 million were approximately $127 million higher than the $656 million incurred in 1998.

Lease and well expenses decreased $7 million to $92 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 Company 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. Depreciation, depletion and amortization ("DD&A") expense increased approximately $145 million to $460 million in 1999 primarily due to charges of $15 million pursuant to a change in the Company'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 the Company's business in the third quarter. General and administrative ("G&A") expenses were $14 million higher than in 1998 due to non-recurring costs of $5 million related to the potential sale of the Company, $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 34% to $1.87 per thousand cubic feet equivalent ("Mcfe") in 1999 from $1.40 per Mcfe in 1998. This increase is primarily due to a higher per unit rate of DD&A expense, G&A expenses and interest expense, partially offset by a lower per unit rate of lease and well expense. Excluding the aforementioned charges of $15 million and $114 million in DD&A expense and $14 million in G&A expenses, the per unit operating costs for the Company were $1.51 per Mcfe. The adjusted per unit operating costs were $0.11 higher compared to $1.40 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.

1998 compared to 1997 During 1998, operating expenses of $656 million were approximately $65 million higher than the $591 million incurred in 1997.

Lease and well expenses increased $3 million to $99 million primarily due to commencement of operations in China. Exploration expenses of $66 million and dry hole expenses of $23 million increased $8 million and $5 million, respectively, from 1997 primarily due to increased exploratory drilling and other exploration activities in North America. Impairment of unproved oil and gas properties increased $5 million to $32 million resulting from a full year of impairment recorded on unproved leases acquired in 1997 in North America. DD&A expense increased approximately $37 million to $315 million in 1998 primarily reflecting a higher per unit rate in North America and increased worldwide production volumes. G&A expenses were $15 million higher than in 1997 due to expanded worldwide operations. Taxes other than income were down by approximately $8 million from the prior year primarily due to lower state severance taxes associated with decreased wellhead revenues in the United States.

Total operating costs per unit of production, which include lease and well, DD&A, G&A, taxes other than income and interest expense, increased 2% to $1.40 per Mcfe in 1998 from $1.37 per Mcfe in 1997. This increase is primarily due to a higher per unit rate of interest expense, DD&A expense and G&A expenses, partially offset by a lower per unit rate of lease and well expense and taxes other than income.

Other Income (Expense) The other income of $611 million for 1999 included a $575 million net gain from the Share Exchange (See Note 7 to the Consolidated Financial Statements), a $59.6 million gain on the sale of 3.2 million options owned by the Company to purchase Enron Corp. common stock (See Note 3 to the Consolidated Financial Statements), and a $19.4 million charge for estimated exit costs related to the Company's decision to dispose of certain international assets.

Interest Expense The increase in net interest expense of $13 million from 1998 to 1999 and $21 million from 1997 to 1998 primarily reflects a higher level of debt outstanding due to expanded worldwide operations and common stock repurchases. (See Note 4 to the Consolidated Financial Statements).

Income Taxes Income tax provision decreased approximately $5 million for 1999 as compared to 1998 and decreased approximately $37 million for 1998 as compared to 1997 primarily due to lower pre-tax income year to year after removing the gain on the Share Exchange which is non-taxable.

Capital Resources and Liquidity

Cash Flow The primary sources of cash for the Company during the three-year period ended December 31, 1999 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 Company shareholders, the repayment of debt and cash contributed to transferred subsidiaries in the Share Exchange.

Net operating cash flows of $442 million in 1999 increased approximately $39 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 year end. 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 $60 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 equity offerings of $725 million and proceeds from sales of treasury stock of $15 million.

Net operating cash flows of $404 million in 1998 decreased approximately $127 million as compared to 1997 primarily reflecting increased working capital for operating activities, higher interest expense, decreased operating revenues, increased cash operating expenses and increased cash taxes. Changes in working capital and other liabilities decreased operating cash flows by $72 million as compared to 1997 primarily due to the payment of $25 million of income taxes due under the 1997 tax agreement with Enron Corp. and changes in accounts receivable, accrued royalties payable and accrued production taxes caused by fluctuation of commodity prices at each year end. Net investing cash outflows of $760 million in 1998 increased by $63 million as compared to 1997 due primarily to increased exploration and development expenditures of $78 million, partially offset by higher proceeds from sales of reserves and related assets of $24 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 provided by financing activities in 1998 was $353 million as compared to $168 million in 1997. Financing activities in 1998 included the net issuance of $402 million of long-term debt primarily to fund exploration and development activities, to repurchase shares of the Company's common stock and to pay cash dividends. Share repurchases in 1998 totaled $26 million as compared to repurchases of $99 million in 1997. Dividend payments were approximately $19 million in each year.

Discretionary cash flow, a frequently used measure of performance for exploration and production companies, is generally derived by adjusting net income 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. The Company generated discretionary cash flow of approximately $476 million in 1999, $463 million in 1998, and $508 million in 1997.

Exploration and Development Expenditures The table below sets out components of actual exploration and development expenditures for the years ended December 31, 1999, 1998 and 1997, along with those budgeted for the year 2000.

Expenditure Category	Actual			Excluding India and China Operations			Budgeted
(In Millions)	**1999**	1998	1997	**1999**	1998	1997	2000
Capital							
Drilling and Facilities	**$ 320**	$ 421	$ 446	**$ 293**	$ 374	$ 385	
Leasehold Acquisitions	**21**	36	77	**21**	36	77	
Producing Property Acquisitions	**45**	211	81	**43**	211	81	
Capitalized Interest and Other	**16**	22	22	**14**	17	14	
Subtotal	**402**	690	626	**371**	638	557	
Exploration Costs	**53**	66	58	**51**	64	53	
Dry Hole Costs	**12**	23	17	**12**	23	17	
Total	**$ 467**	$ 779	$ 701	**$ 434**	$ 725	$ 627	$500-$525

Exploration and development expenditures decreased $312 million in 1999 as compared to 1998 primarily due to a reduced level of service industry costs as well as reduced spending on the North America, Trinidad and India drilling and acquisition program. Producing property acquisitions decreased $166 million primarily in North America. Drilling and facilities expenditures declined by $101 million in 1999 primarily due to implementation of cost provisions of certain new service agreements in North America and effects of the Share Exchange.

Exploration and development expenditures increased $78 million in 1998 as compared to 1997 primarily due to the third quarter 1998 acquisition of producing properties in the Gulf of Mexico for $156 million. Unproved leasehold acquisitions decreased $41 million primarily in North America. Drilling and facilities expenditures declined by approximately $25 million in 1998 as decreased activity in North America and lower expenditures in India were partially offset by new drilling in Trinidad and Venezuela. While development activities continued in India, expenditures in 1998 were less than in 1997 due to 1997 expenditures associated with the installation of permanent production facilities.

Hedging Transactions The Company's 1999 NYMEX-related natural gas and crude oil commodity price swaps closed with "other marketing revenue" decreases of $7 million and $3 million pretax, respectively. At December 31, 1999, there were open crude oil commodity price swaps for 2000 covering approximately 548 MBbl of crude oil at a weighted average price of $19.23 per barrel. There were no open natural gas commodity price swaps.

Financing The Company's long-term debt-to-total-capital ratio was 47% as of December 31, 1999 and 1998.

During 1999, total long-term debt decreased $153 million to $990 million following the issuance of two series of preferred stock with combined face value of $150 million and the subsequent use of approximately $147 million of net proceeds received therefrom to reduce commercial paper and bank debt borrowings. (See Notes 4 and 6 to the Consolidated Financial Statements). The estimated fair value of the Company's long-term debt at December 31, 1999 and 1998 was $933 million and $1,141 million, respectively, based upon quoted market prices and, where such prices were not available, upon interest rates currently available to the Company at year end. The Company's debt is primarily at fixed interest rates. At December 31, 1999, a 1% change in interest rates would result in a $46 million change in the estimated fair value of the fixed rate obligations. (See Note 14 to the Consolidated Financial Statements).

Prior to August 16, 1999, the Company engaged in various transactions with Enron Corp. that were characteristic of a consolidated group under common control. Accordingly, the Company maintained reciprocal agreements with Enron Corp. that provided for the borrowing by the Company of up to $200 million and investing by the Company of surplus funds of up to $200 million at market-based interest rates. Advances from Enron Corp. of $200 million were outstanding at December 31, 1998, and such balances were classified as long-term based on the Company's intent and ability to ultimately replace such amounts with other long-term debt. The reciprocal agreements terminated on August 16, 1999 upon the closing of the Share Exchange. There were no investments with Enron Corp. at December 31, 1998 or 1999. (See Note 4 to the Consolidated Financial Statements).

Outlook 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 that are tending to mitigate the impacts of fewer crude oil and natural gas wells being drilled, improvements being realized in the availability and utilization of natural gas storage capacity and warmer than normal weather experienced in 1999 and to date in 2000. However, the continually 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 and a supporting/strengthening of the overall natural gas market over time. Being primarily a natural gas producer, the Company is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate prices. At December 31, 1999, based on the Company's tax position and the portion of the

Company's anticipated natural gas volumes for 2000 for which prices have not, in effect, been hedged using NYMEX-related commodity market transactions and long-term marketing contracts, the Company's net income and current operating cash flow sensitivities to changing natural gas prices are approximately $18 million (or $.15 per share) and $28 million, respectively, for each $.10 per Mcf change in average wellhead natural gas prices. The Company is not impacted as significantly by changing crude oil prices for those volumes not otherwise hedged. The Company's net income and current operating cash flow sensitivities are approximately $5 million (or $.04 per share) and $8 million, respectively, for each $1.00 per barrel change in average wellhead crude oil prices.

The Company plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in North America. However, based on the continuing uncertainty associated with North America natural gas prices and as a result of the overall success realized in Trinidad, the Company anticipates expending a portion of its available funds in the further development of opportunities outside North America. In addition, the Company 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 2000 expenditures are anticipated to be managed within the range of $500-$525 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 2000 are structured to maintain the flexibility necessary under the Company'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 2000 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, the Company believes net operating cash flow and available financing alternatives in 2000 will be sufficient to fund its net investing cash requirements for the year. However, the Company has significant flexibility with respect to its financing alternatives and adjustment of its exploration, exploitation, development and acquisition expenditure plans if circumstances warrant. While the Company 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 the Company.

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 the Company'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 the Company's operations or financial condition. It is not anticipated, based on current laws and regulations, that the Company 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, the Company 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 delays the effective date of SFAS No. 133 for one year, to fiscal years beginning after June 15, 2000. SFAS No. 133, as amended by SFAS No. 137, 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 the Company 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.

The Company has not yet quantified the impact of adopting SFAS No. 133 on its financial statements and has not determined the timing of adoption. Based on the Company's current level of derivative and hedging activities, the Company does not expect the impact of adoption to be material.

Year 2000

The Company did not experience any significant operational difficulties or incur any significant expenses in connection with the Year 2000 issue. The Company will continue to monitor all critical systems for any incidents of delayed complications or disruptions and problems encountered through third parties with whom the Company deals so that they may be timely addressed.

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 the Company's future financial position, business strategy, budgets, reserve information, projected levels of production, exploration and development expenditures, projected costs and plans and objectives of management for future operations, are forward-looking statements. The Company 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 generate income or cash flows are forward-looking statements. Although the Company 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 the Company'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 the Company's forward-looking statements might not occur. The Company 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. (formerly Enron Oil & Gas Company, a Delaware corporation) and subsidiaries as of December 31, 1999 and 1998, 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, 1999. 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, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Houston, Texas
March 2, 2000

Management's Responsibility for Financial Reporting

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

Arthur Andersen LLP, independent public accountants, was engaged to audit the consolidated financial statements of EOG Resources, Inc. and its subsidiaries 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 Resources, Inc. and its subsidiaries 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 Resources, Inc. and its subsidiaries and the accounting principles employed in financial reporting by the Company 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 the Company. 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, the Company 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, 1999.

Mark G. Papa
Chairman and
Chief Executive Officer

Walter C. Wilson
Senior Vice President and
Chief Financial Officer

Timothy K. Driggers
Vice President and Controller

Houston, Texas
March 2, 2000

Consolidated Statements of Income and Comprehensive Income

(In Thousands, Except Per Share Amounts)	Year Ended December 31, 1999	1998	1997
Net Operating Revenues			
Natural Gas			
Trade	**$ 588,432**	$ 558,376	$ 544,181
Associated Companies	**56,450**	62,929	71,339
Crude Oil, Condensate and Natural Gas Liquids			
Trade	**156,441**	120,366	121,838
Associated Companies	**826**	9,266	29,951
Gains (Losses) on Sales of Reserves and Related Assets and Other, Net	**(743)**	18,251	16,192
Total	**801,406**	769,188	783,501
Operating Expenses			
Lease and Well	**91,540**	98,868	96,064
Exploration Costs	**52,773**	65,940	57,696
Dry Hole Costs	**11,893**	22,751	17,303
Impairment of Unproved Oil and Gas Properties	**31,608**	32,076	27,213
Depreciation, Depletion and Amortization	**459,877**	315,106	278,179
General and Administrative	**82,857**	69,010	54,415
Taxes Other Than Income	**52,670**	51,776	59,856
Total	**783,218**	655,527	590,726
Operating Income	**18,188**	113,661	192,775
Other Income (Expense)			
Gain on Share Exchange	**575,151**	—	—
Other, Net	**36,192**	(4,800)	(1,588)
Total	**611,343**	(4,800)	(1,588)
Income Before Interest Expense and Income Taxes	**629,531**	108,861	191,187
Interest Expense			
Incurred			
Trade	**72,157**	60,701	41,399
Affiliate	**256**	589	24
Capitalized	**(10,594)**	(12,711)	(13,706)
Net Interest Expense	**61,819**	48,579	27,717
Income Before Income Taxes	**567,712**	60,282	163,470
Income Tax Provision (Benefit)	**(1,382)**	4,111	41,500
Net Income	**569,094**	56,171	121,970
Preferred Stock Dividends	**(535)**	—	—
Net Income Available to Common	**568,559**	56,171	121,970
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustment	**16,038**	(16,077)	(9,592)
Comprehensive Income	**$ 584,597**	$ 40,094	$ 112,378
Net Income Per Share Available to Common			
Basic	**$ 4.04**	$ .36	$ .78
Diluted	**$ 3.99**	$ .36	$ .77
Average Number of Common Shares			
Basic	**140,869**	154,345	157,376
Diluted	**142,352**	155,054	158,160

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

Consolidated Balance Sheets

(In Thousands)	At December 31, 1999	1998
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 24,836**	$ 6,303
Accounts Receivable		
Trade	**148,189**	176,608
Associated Companies	**—**	16,980
Inventories	**18,816**	39,581
Other	**8,660**	6,878
Total	**200,501**	246,350
Oil and Gas Properties (Successful Efforts Method)	**4,602,740**	4,814,425
Less Accumulated Depreciation, Depletion and Amortization	**(2,267,812)**	(2,138,062)
Net Oil and Gas Properties	**2,334,928**	2,676,363
Other Assets	**75,364**	95,382
Total Assets	**$ 2,610,793**	$ 3,018,095
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable		
Trade	**$ 172,780**	$ 159,690
Associated Companies	**—**	46,597
Accrued Taxes Payable	**19,648**	20,087
Dividends Payable	**4,227**	4,710
Other	**21,963**	31,550
Total	**218,618**	262,634
Long-Term Debt		
Trade	**990,306**	942,779
Affiliate	**—**	200,000
Other Liabilities		
Trade	**46,306**	21,516
Associated Companies	**—**	46,327
Deferred Income Taxes	**225,952**	260,337
Deferred Revenue	**—**	4,198
Shareholders' Equity		
Preferred Stock, $.01 Par, 10,000,000 Shares Authorized:		
Series A, 100,000 Shares Issued, Cumulative, $100,000,000 Liquidation Preference	**97,909**	—
Series C, 500 Shares Issued, Cumulative, $50,000,000 Liquidation Preference	**49,281**	—
Common Stock, $.01 Par, 320,000,000 Shares Authorized; 124,730,000 Shares Issued at December 31, 1999 and 160,000,000 Shares Issued at December 31, 1998	**201,247**	201,600
Additional Paid In Capital	**—**	401,524
Unearned Compensation	**(1,618)**	(4,900)
Cumulative Foreign Currency Translation Adjustment	**(19,810)**	(35,848)
Retained Earnings	**930,938**	838,371
Common Stock Held in Treasury, 5,625,446 shares at December 31, 1999 and 6,276,156 shares at December 31, 1998	**(128,336)**	(120,443)
Total Shareholders' Equity	**1,129,611**	1,280,304
Total Liabilities and Shareholders' Equity	**$ 2,610,793**	$ 3,018,095

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	Cumulative Foreign Currency Translation Adjustment	Retained Earnings	Common Stock Held In Treasury	Total Shareholders' Equity
Balance at December 31, 1996	$ —	$ 201,600	$ 388,212	$ (5,727)	$ (10,179)	$ 697,564	$ (6,380)	$ 1,265,090
Net Income	—	—	—	—	—	121,970	—	121,970
Dividends Paid/Declared, $.12 Per Share	—	—	—	—	—	(18,825)	—	(18,825)
Translation Adjustment	—	—	—	—	(9,592)	—	—	(9,592)
Treasury Stock Purchased	—	—	—	—	—	—	(99,306)	(99,306)
Treasury Stock Issued Under Stock Option Plans	—	—	(872)	—	—	—	6,014	5,142
Options Granted by Enron Corp.	—	—	15,081	—	—	—	—	15,081
Amortization of Unearned Compensation	—	—	—	1,033	—	—	—	1,033
Other	—	—	456	—	—	—	—	456
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
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	—	—	(492)	(1,709)	—	—	5,104	2,903
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 Accrued	—	—	—	—	—	(535)	—	(535)
Common Stock Dividends Paid/Declared, $.12 Per Share	—	—	—	—	—	(16,377)	—	(16,377)
Translation Adjustment	—	—	—	—	16,038	—	—	16,038
Treasury Stock Purchased	—	—	—	—	—	—	(2,143)	(2,143)
Treasury Stock Received in Share Exchange	—	—	—	—	—	—	(1,459,484)	(1,459,484)
Common Stock Retired	—	(623)	(978,224)	—	—	(458,033)	1,436,880	—
Treasury Stock Issued Under Stock Option Plans	—	—	(887)	136	—	(1,582)	16,854	14,521
Amortization of Unearned Compensation	—	—	—	3,146	—	—	—	3,146
Other	—	—	(75)	—	—	—	—	(75)
Balance at December 31, 1999	**$ 147,190**	**$ 201,247**	**$ —**	**$ (1,618)**	**$ (19,810)**	**$ 930,938**	**$ (128,336)**	**$ 1,129,611**

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

Consolidated Statements of Cash Flows

(In Thousands)	Year Ended December 31, 1999	1998	1997
Cash Flows from Operating Activities			
Reconciliation of Net Income to Net Operating Cash Inflows:			
Net Income	**$ 569,094**	$ 56,171	$ 121,970
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	**459,877**	315,106	278,179
Impairment of Unproved Oil and Gas Properties	**31,608**	32,076	27,213
Deferred Income Taxes	**(26,252)**	(26,794)	16,665
Other, Net	**25,583**	7,761	359
Exploration Costs	**52,773**	65,940	57,696
Dry Hole Costs	**11,893**	22,751	17,303
Losses (Gains) On Sales of Reserves and Related Assets and Other, Net	**5,602**	(11,191)	(9,287)
Gains on Sales of Other Assets	**(59,647)**	—	—
Gain on Share Exchange	**(575,151)**	—	—
Other, Net	**(19,081)**	1,116	(2,590)
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	**(12,914)**	36,363	48,893
Inventories	**5,180**	(7,541)	(11,294)
Accounts Payable	**4,395**	(65,249)	(11,478)
Accrued Taxes Payable	**2,449**	(8,754)	10,287
Other Liabilities	**(15,438)**	2,324	2,521
Other, Net	**(9,960)**	(3,620)	9,760
Amortization of Deferred Revenue	**—**	(43,344)	(43,345)
Changes in Components of Working Capital Associated with Investing and Financing Activities	**(7,879)**	30,491	18,077
Net Operating Cash Inflows	**442,132**	403,606	530,929
Investing Cash Flows			
Additions to Oil and Gas Properties	**(402,829)**	(690,352)	(626,198)
Exploration Costs	**(52,773)**	(65,940)	(57,696)
Dry Hole Costs	**(11,893)**	(22,751)	(17,303)
Proceeds from Sales of Reserves and Related Assets	**10,934**	61,858	37,521
Proceeds from Sales of Other Assets	**82,965**	—	—
Changes in Components of Working Capital Associated with Investing Activities	**7,909**	(30,173)	(22,454)
Other, Net	**2,322**	(12,262)	(11,000)
Net Investing Cash Outflows	**(363,365)**	(759,620)	(697,130)
Financing Cash Flows			
Long-Term Debt			
Trade	**47,527**	394,004	86,595
Affiliate	**(200,000)**	7,500	192,500
Proceeds from Preferred Stock Issued	**147,175**	—	—
Proceeds from Common Stock Issued	**577,932**	—	—
Dividends Paid	**(17,395)**	(18,504)	(18,938)
Treasury Stock Purchased	**(2,143)**	(25,875)	(99,306)
Proceeds from Sales of Treasury Stock	**14,728**	2,883	5,141
Equity Contribution to Transferred Subsidiaries	**(608,750)**	—	—
Other, Net	**(19,308)**	(7,021)	1,895
Net Financing Cash Inflows (Outflows)	**(60,234)**	352,987	167,887
Increase (Decrease) in Cash and Cash Equivalents	**18,533**	(3,027)	1,686
Cash and Cash Equivalents at Beginning of Year	**6,303**	9,330	7,644
Cash and Cash Equivalents at End of Year	**$ 24,836**	$ 6,303	$ 9,330

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

Notes to Consolidated Financial Statements

(Details in Thousands Unless Otherwise Indicated)

1. Summary of Significant Accounting Policies

Principles of Consolidation The consolidated financial statements of EOG Resources, Inc., formerly Enron Oil & Gas Company (the "Company") 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 The Company records as cash equivalents all highly liquid short-term investments with original maturities of three months or less. The Company had approximately $23 million of outstanding checks payable classified as accounts payable at December 31, 1999.

Oil and Gas Operations The Company 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, the Company 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 the Company'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 the Company'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 the Company's strategy of continuing such sales in order to maximize the economic value of its assets.

Accounting for Price Risk Management The Company 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. 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.

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 exploratory drilling and related facilities with significant cash outlays.

Income Taxes The Company accounts for income taxes under the provisions of SFAS No. 109 - "Accounting for Income Taxes." SFAS No. 109 requires the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases (See Note 8 "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 10 "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. Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues

Natural gas revenues, trade for 1999, 1998 and 1997 are net of costs of natural gas purchased for sale related to natural gas marketing activities of $44.6 million, $44.8 million and $73.6 million, respectively. Natural gas revenues, associated for 1999, 1998 and 1997 are net of costs of natural gas purchased for sale related to natural gas marketing activities of $13.5 million, $51.0 million and $47.7 million, respectively.

In March 1995, in a series of transactions with Enron Corp. and an affiliate of Enron Corp., the Company exchanged all of its fuel supply and purchase contracts and related price swap agreements associated with a Texas City cogeneration plant (the "Cogen Contracts") for certain natural gas price swap agreements of equivalent value issued by the affiliate that are designated as hedges (the "Swap Agreements"). Such Swap Agreements were closed on March 31, 1995. As a result of the transactions, the Company was relieved of all performance obligations associated with the Cogen Contracts. The Company realized net operating revenues and received corresponding cash payments of approximately $91 million during the period extending through December 31, 1999, under the terms of the closed Swap Agreements. The estimated fair value of the Swap Agreements was approximately $81 million at the date the Swap Agreements were received in exchange for the Cogen Contracts. The net effect of this series of transactions resulted in increases in net operating revenues and cash receipts for the Company during 1995 and 1996 of approximately $13 million and $7 million, respectively, with offsetting decreases in 1998 and 1999 versus that anticipated under the Cogen Contracts.

3. Other Assets

In December 1997, the Company and Enron Corp. entered into an Equity Participation and Business Opportunity Agreement. Among other things, under the agreement, Enron Corp. granted to the Company options to purchase 3.2 million shares of Enron Corp. common stock at a price of $39.1875 per share which was the closing price of the stock on the date that the agreement was approved by the Board of Directors of the Company. Other Assets at December 31, 1998 includes $23.3 million or $7.29 per share representing the estimated fair value of the Enron Corp. stock options at the date of grant. Such estimated fair value was determined using the Black-Scholes option-pricing model with the following weighted-average assumptions at the date the options were issued: (1) dividend yield of 2.5%, (2) expected volatility of 17.5%, (3) risk-free interest rate of 5.85%, and (4) expected average life of 4.0 years. Receipt of the options represented a capital contribution from Enron Corp. and, accordingly, the fair value received, net of tax effects of $8.2 million, was credited to Additional Paid In Capital.

During the first and second quarters of 1999, the Company sold the 3.2 million options to purchase common stock of Enron Corp. In the first quarter of 1999, the Company sold 1.6 million options at an average price of $24.81 ($64.00 Enron Corp. stock price equivalent), realizing net proceeds of $40 million and a gain of $28 million pre-tax ($18 million after-tax). Early in the second quarter, the Company sold the remaining 1.6 million options at an average price of $27.07 ($66.26 Enron Corp. stock price equivalent), realizing net proceeds of $43 million and a gain of $32 million pre-tax ($21 million after-tax). The gain on sale of the options is included in other income (expense) - other, net in the Consolidated Statements of Income and Comprehensive Income. These transactions were completed prior to Enron Corp. effecting a two-for-one stock split.

4. Long-Term Debt

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

(In Thousands)	1999	1998
Commercial Paper	**$ 123,186**	$ 162,539
Uncommitted Credit Facilities	**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
Other	**120**	240
	990,306	942,779
Affiliate	**—**	200,000
Total	**$ 990,306**	$ 1,142,779

During 1999, the Company entered into two new credit facilities with domestic and foreign banks which provide for an aggregate of $800 million in long-term committed credit, with $400 million expiring in 2000 and $400 million expiring in 2004, and concurrently cancelled the existing $450 million facility. With respect to the $400 million expiring in 2000, the Company 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 the Company, based upon a base rate or a Eurodollar rate. At December 31, 1999, 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 are classified as long-term debt based on the Company's intent and ability to ultimately replace such amounts with other long-term debt. (See Note 14 "Price and Interest Rate Risk Management").

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 bears interest at variable market-based rates and is guaranteed by the Company.

At December 31, 1999, the aggregate annual maturities of long-term debt outstanding were less than $1.0 million for 2000, $105 million for 2001, none for 2002 and 2003 and $100 million for 2004.

See Note 14 "Price and Interest Rate Risk Management."

Shelf Registration The Company may sell from time to time up to an aggregate of approximately $88 million in debt securities and/or common stock pursuant to an effective "shelf" registration statement filed with the Securities and Exchange Commission.

Financing Arrangements With Enron Corp Prior to August 16, 1999, the Company engaged in various transactions with Enron Corp. that were characteristic of a consolidated group under common control. Accordingly, the Company maintained reciprocal agreements with Enron Corp. that provided for the borrowing by the Company of up to $200 million and investing by the Company of surplus funds of up to $200 million at market-based interest rates. Advances from Enron Corp. of $200 million were outstanding at December 31, 1998, and such balances were classified as long-term based on the Company's intent and ability to ultimately replace such amounts with other long-term debt. The reciprocal agreements terminated on August 16, 1999 upon the closing of the Share Exchange. There were no investments with Enron Corp. at December 31, 1998 or 1999. (See Note 14 "Price and Interest Rate Risk Management").

Fair Value Of Long-Term Debt At December 31, 1999 and 1998, the Company had $990 million and $1,143 million, respectively, of long-term debt which had fair values of approximately $933 million and $1,141 million, respectively. The fair value of long-term debt is the value the Company 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 the Company at year-end.

5. Volumetric Production Payment

In September 1992, the Company sold a volumetric production payment for $326.8 million to a limited partnership. Under the terms of the production payment, as amended October 1, 1993, the Company conveyed a real property interest in certain natural gas and other hydrocarbons to the purchaser. Deliveries were scheduled at the rate of 50 billion British thermal units per day through March 31, 1999. The Company accounted for the proceeds received in the transaction as deferred revenue, which was amortized into revenue and income as natural gas and other hydrocarbons were produced and delivered during the term of the volumetric production payment agreement. In December 1998, the Company settled the remainder of the contract in cash which was not materially different from the recorded deferred revenue, and delivery obligations were terminated.

6. Shareholders' Equity

The Board of Directors of the Company has approved an authorization for purchasing and holding in treasury at any time up to 1,000,000 shares of common stock of the Company for the purpose of, but not limited to, meeting obligations associated with the exercise of stock options granted to qualified employees pursuant to the Company's stock option plans. The Board of Directors has also approved the selling from time to time, subject to certain conditions, of put options on the common stock of the Company. The 1,000,000 share limit mentioned above applies to shares held in treasury and unexpired put options outstanding. In February 1997, as amended in February 1998, the Board of Directors authorized the additional purchase of up to an aggregate maximum of 10 million shares of common stock of the Company 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 the Company's stock option plans and any other approved transactions or activities for which such common stock shall be required. At December 31, 1999 and 1998, 5,625,446 shares and 6,276,156 shares, respectively, were held in treasury under these authorizations. In February 2000, the Board of Directors authorized the purchase of an aggregate maximum of 10 million shares of common stock of the Company which replaced the remaining authorization from February 1998. (See Note 9

"Commitments and Contingencies - Treasury Shares"). The Company has, from time to time, entered into transactions in which it writes put options on its own common stock. 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, the Company filed a registration statement with the Securities and Exchange Commission for the public offering of 27,000,000 shares of the Company'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 7 "Transactions with Enron Corp. and Related Parties." As a result of the public offering and the retirement of the 62,270,000 shares of the Company's common stock received from Enron Corp. in the Share Exchange transaction, the number of shares of the Company's common stock issued was reduced to 124,730,000 from 160,000,000 prior to the Share Exchange.

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

Series A On December 10, 1999 the Company 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. Subject to the terms of a registration rights agreement, the Company is required to register these shares for public sale within 150 days of the issuance date. Dividends will be payable on the shares only if declared by the Company'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 within the first 18 months of the issuance date. The Company 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 the Company.

Series C On December 22, 1999, the Company 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. Subject to the terms of a registration rights agreement, the Company is required to register these shares for public sale within 150 days of the issuance date. Dividends will be payable on the shares only if declared by the Company'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 the Company has elected a "Non-Call Period" for a subsequent dividend period), the Company may redeem the shares, in whole or in part, on any dividend payment date at $100,000 per share upon the payment of 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 the Company.

7. Transactions with Enron Corp. and Related Parties

On August 16, 1999, the Company and Enron Corp. completed the Share Exchange whereby the Company received 62,270,000 shares of the Company's common stock out of 82,270,000 shares owned by Enron Corp. in exchange for all the stock of the Company's subsidiary, EOGI-India, Inc. Prior to the Share Exchange, the Company 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 the Company's assets and operations in India and China. The Company 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, the Company retired the 62,270,000 shares of the Company'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 the Company. On August 30, 1999, the Company 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 the Company's common stock, representing approximately 53.5 percent of all of the shares of the Company'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 the Company'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 the Company's common stock, Enron Corp's maximum remaining interest in the Company 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 the Company's common stock). As a result, beginning with the Share Exchange all transactions with Enron Corp. and its affiliates have been classified as Trade.

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

Business Opportunity Agreement In December 1997, Enron Corp. and the Company entered into the Equity Participation and Business Opportunity Agreement ("Business Opportunity Agreement") which defined certain obligations that Enron Corp. owed to the Company and relieved Enron Corp. from certain obligations to the Company that it might otherwise have, including the obligation to offer certain business opportunities to the Company. The Business Opportunity Agreement was approved by the Board of Directors of the Company after it was approved unanimously by a special committee of the Board of Directors consisting of the Company's independent directors.

The Business Opportunity Agreement provided generally that, so long as such activities were conducted in compliance with the Business Opportunity Agreement in all material respects, Enron Corp. could pursue business opportunities independently of the Company.

In consideration for the Company's agreements in the Business Opportunity Agreement, Enron Corp. provided valuable consideration to the Company, including options to purchase common stock of Enron Corp., all of which were sold by the Company during 1999 (see Note 3 "Other Assets").

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. (See Note 2 "Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues"). 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 14 "Price and Interest Rate Risk Management").

General and Administrative Expenses Prior to the Share Exchange, the Company was charged by Enron Corp. for all direct costs associated with its operations. Such direct charges, excluding benefit plan charges (See Note 9 "Commitments and Contingencies - Employee Benefit Plans"), totaled $10.6 million, $14.2 million and $16.1 million for the years ended December 31, 1999, 1998 and 1997, 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, $5.1 million and $5.3 million was incurred by the Company for indirect general and administrative expenses for 1999, 1998 and 1997, respectively. Management believes that these charges were reasonable.

Financing See Note 4 "Long-Term Debt - Financing Arrangements with Enron Corp." for a discussion of financing arrangements with Enron Corp.

8. Income Taxes

The principal components of the Company's net deferred income tax liability at December 31, 1999 and 1998 were as follows:

(In Thousands)	**1999**	1998
Deferred Income Tax Assets		
Cogen Contract Exchange	**$ —**	$ 9,519
Net Operating Loss		
Carryforward, India	**—**	44,640
Non-Producing Leasehold Costs	**25,199**	19,411
Seismic Costs Capitalized for Tax	**9,912**	7,687
Alternative Minimum Tax		
Credit Carryforward	**21,772**	17,656
Trading Activity	**1,426**	4,253
Section 29 Credit Monetization	**15,657**	—
Other	**13,993**	12,084
Total Deferred Income Tax Assets	**87,959**	115,250
Deferred Income Tax Liabilities		
Oil and Gas Exploration and		
Development Costs Deducted		
for Tax Over Book Depreciation,		
Depletion and Amortization	**299,704**	360,045
Capitalized Interest	**11,986**	12,512
Other	**2,221**	3,030
Total Deferred Income		
Tax Liabilities	**313,911**	375,587
Net Deferred Income Tax Liability	**$ 225,952**	$ 260,337

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

(In Thousands)	**1999**	1998	1997
United States	**$ 561,841**	$ (3,297)	$ 103,831
Foreign	**5,871**	63,579	59,639
Total	**$ 567,712**	$ 60,282	$ 163,470

Total income tax provision (benefit) was as follows:

(In Thousands)	**1999**	1998	1997
Current:			
Federal	**$ 5,510**	$ 10,496	$ 50,494
State	**3,234**	1,474	840
Foreign	**16,126**	18,935	23,614
Total	**24,870**	30,905	74,948
Deferred:			
Federal	**(49,474)**	(31,279)	(32,711)
State	**(502)**	(4,589)	348
Foreign	**23,724**	9,074	(1,085)
Total	**(26,252)**	(26,794)	(33,448)
Income Tax Provision			
(Benefit)	**$ (1,382)**	$ 4,111	$ 41,500

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

	1999	1998	1997
Statutory Federal			
Income Tax Rate	**35.00%**	35.00%	35.00%
State Income Tax,			
Net of Federal Benefit	**0.31**	(3.36)	0.47
Income Tax Related			
to Foreign Operations	**1.60**	4.76	2.83
Tight Gas Sand Federal			
Income Tax Credits	**(1.45)**	(17.36)	(7.51)
Revision of Prior Years' Tax			
Estimates	**(0.21)**	(10.78)	(4.34)
Share Exchange	**(35.46)**	—	—
Other	**(.03)**	(1.45)	(1.06)
Effective Income Tax Rate	**(0.24)%**	6.81%	25.39%

In 1997, the Company and Enron Corp. agreed to replace an existing tax allocation agreement with a new tax allocation agreement. In the new agreement, Enron Corp. agreed to refund a $13 million payment made by the Company pursuant to the existing agreement, the Company agreed to release Enron Corp. from the liabilities assumed related to the $13 million payment and the parties agreed to indemnify each other in a manner consistent with a former agreement. Enron Corp. also advanced the Company approximately $50 million to fund certain federal income taxes related to the 1995 taxable year. This advance was scheduled to be repaid in annual installments through January 1, 2001. Final payment to Enron was made on August 16, 1999.

The Company's foreign subsidiaries' undistributed earnings of approximately $275 million at December 31, 1999 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, the Company 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.

The Company has an alternative minimum tax ("AMT") credit carryforward of $22 million which can be used to offset regular income taxes payable in future years. The AMT credit carryforward has an indefinite carryforward period.

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

9. Commitments and Contingencies

Employee Benefit Plans Employees of the Company 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, 1998, and 1997, the Company was charged $4.4 million, $6.4 million and $5.0 million, respectively, for all such benefits, including pension expense totaling $.9 million, $1.3 million and $1.0 million, respectively, by Enron Corp.

Since August 1999, the Company has adopted defined contribution pension plans for most of its employees in the United States. The Company'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, a substantial part of which was funded currently.

The Company 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 the Company's operations.

Stock Plans

Stock Options The Company has various stock plans ("the Plans") under which employees of the Company and its subsidiaries and nonemployee members of the Board of Directors have been or may be granted rights to purchase shares of common stock of the Company 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.

The Company 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, the Company 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):

	1999		1998		1997	
	Options	Average Grant Price	Options	Average Grant Price	Options	Average Grant Price
Outstanding at January 1	**15,036**	**$ 18.35**	9,735	$ 19.99	8,796	$ 20.70
Granted	**1,272**	**19.88**	5,949	15.76	3,079	20.18
Exercised	**(822)**	**16.22**	(172)	15.14	(261)	17.16
Forfeited	**(2,827)**	**18.26**	(476)	20.62	(1,879)	24.06
Outstanding at December 31	**12,659**	**18.66**	15,036	18.35	9,735	19.99
Options Exercisable at December 31	**8,118**	**19.23**	7,703	19.38	5,618	19.70
Options Available for Future Grant	**5,564**		3,098		2,519	
Average Fair Value of Options Granted During Year	**$ 7.43**		$ 4.75		$ 6.96	

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 1999, 1998, and 1997, respectively: (1) dividend yield of 0.6%, 0.6% and 0.6%, (2) expected volatility of 28%, 26%, and 27%, (3) risk-free interest rate of 5.9%, 5.1%, and 6.3%, and (4) expected life of 6.0 years, 4.9 years and 5.2 years.

During 1997, in response to extremely competitive conditions for technical personnel, the Company cancelled options issued in 1996 to purchase 1,282,000 shares of common stock at an exercise price of $25.38 per share, and reissued the same number of options with an exercise price of $18.25 per share. The reissue did not involve any executive officers of the Company.

The following table summarizes certain information for the options outstanding at December 31, 1999 (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	339	2	$ 9.77	339	$ 9.77
13.00 to 17.99	3,923	8	15.05	1,956	15.73
18.00 to 22.99	7,084	6	20.14	4,741	20.32
23.00 to 29.00	1,313	5	23.78	1,082	23.77
9.00 to 29.00	12,659	6	18.66	8,118	19.23

The Company's pro forma net income and net income per share available to common for 1999, 1998 and 1997, had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions except per share data):

	1999		1998		1997	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net Income Available to Common	**$ 568.6**	**$ 566.3**	$ 56.2	$ 47.3	$ 122.0	$ 116.7
Net Income per Share Available to Common						
Basic	**$ 4.04**	**$ 4.02**	$ .36	$ .31	$ .78	$ .74
Diluted	**$ 3.99**	**$ 3.98**	$ .36	$ .30	$ .77	$ .74

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 the Company 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 the Company'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 the Company's stock option awards.

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

	Restricted Shares		
	1999	1998	1997
Outstanding at January 1	**345,334**	284,000	284,000
Granted	**23,000**	108,500	—
Released to Participants	**(37,166)**	(14,166)	—
Forfeited or Expired	**(66,000)**	(33,000)	—
Outstanding at December 31	**265,168**	345,334	284,000
Average Fair Value of Shares Granted During Year	**$ 21.43**	$ 20.11	$ —

The fair value of the restricted shares at date of grant has been recorded in shareholders' equity as unearned compensation and is being amortized as compensation expense. Related compensation expense for 1999, 1998 and 1997 was approximately $3.1 million, $1.5 million and $1.0 million, respectively.

Treasury Shares During 1999, 1998 and 1997, the Company purchased or was tendered 130,000, 1,590,200, and 4,954,344 of its common shares, respectively, and delivered such shares upon the exercise of stock options and awards of restricted stock, except for shares held in treasury at December 31, 1999, 1998 and 1997. The difference between the cost of the treasury shares and the exercise price of the options, net of federal income tax benefit of $1.4 million, $.3 million, and $.5 million for the years 1999, 1998 and 1997, respectively, is reflected as an adjustment to Additional Paid In Capital through August 1999 and Retained Earnings thereafter as a result of the share retirement described in Note 7. In December 1992, as amended in September 1994 and December 1996, the Company commenced a stock repurchase program of up to 1,000,000 shares authorized by the Board of Directors to facilitate the availability of treasury shares of common stock for, but not limited to, the settlement of employee stock option exercises pursuant to the Plans. In February 1997 as amended in February 1998, the Board of Directors authorized the additional purchase of up to 10 million shares for similar purposes. At December 31, 1999 and 1998, 5,625,446 and 6,276,156 shares, respectively, were held in treasury under these authorizations. In February 2000, the Board of Directors authorized the purchase of an aggregate maximum of 10 million shares of common stock of the Company which replaced the remaining authorization from February 1998. (See Note 6 "Shareholders' Equity").

Letters Of Credit At December 31, 1999 and 1998, the Company had letters of credit and guaranties outstanding totaling approximately $118 million and $127 million, respectively.

Contingencies On July 21, 1999, two stockholders of the Company filed separate lawsuits purportedly on behalf of the Company against Enron Corp. and those individuals who were then directors of the Company, 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. The Company, Enron Corp. and the individual defendants believe the lawsuits are without merit and intend to vigorously contest them. There are various other suits and claims against the Company 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 the Company. The Company 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 the Company.

10. Net Income Per Share Available to Common

The difference between the Average Number of Common Shares outstanding for basic and diluted net income per share of common stock is due to the assumed issuance of approximately 1,483,132, 709,000, and 784,000 common shares relating to employee stock options in 1999, 1998 and 1997, respectively.

11. Cash Flow Information

On August 16, 1999, the Company and Enron Corp. completed the Share Exchange whereby the Company received 62,270,000 shares of the Company's common stock out of 82,270,000 shares owned by Enron Corp. in exchange for all the stock of the Company's subsidiary, EOGI-India, Inc (see Note 7 "Transactions with Enron Corp. and Related Parties"). Prior to the Share Exchange, the Company 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, the Company's net investment in EOGI-India, Inc. was $870 million.

On December 31, 1999, the Company completed an exchange agreement with OXY USA Inc. The acquired properties were assigned the net book value of the properties transferred of $ 88 million, resulting in no gain or loss.

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

(In Thousands)	**1999**	1998	1997
Interest (net of amount capitalized)	**$ 67,965**	$ 51,166	$ 27,759
Income taxes	**19,810**	38,551	28,708

12. Business Segment Information

The Company's operations are all natural gas and crude oil exploration and production related. The Company adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," during the fourth quarter of 1998. SFAS No. 131 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. The Company'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 the Company'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
1999						
Net Operating Revenues	**$ 600,315[3]**	**$ 94,739[3]**	**$ 62,689**	**$ 51,554**	**$ (7,891)**	**$ 801,406[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	**298,660**	**63,071**	**8,175**	**23,820**	**9,103**	**402,829**
Total Assets	**2,118,843**	**344,465**	**145,186**	**—**	**2,299**	**2,610,793**
1998						
Net Operating Revenues	$ 564,378	$ 68,622	$ 66,967	$ 72,826	$ (3,605)	$ 769,188
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 Income (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	547,209	49,142	19,347	46,657	27,997	690,352
Total Assets	2,238,969	277,861	131,964	289,596	79,705	3,018,095
1997						
Net Operating Revenues	$ 603,845	$ 73,466	$ 66,000	$ 35,332	$ 4,858	$ 783,501
Depreciation, Depletion and Amortization	239,418	23,116	11,031	3,716	898	278,179
Operating Income (Loss)	138,213	19,983	38,968	13,794	(18,183)	192,775
Interest Income	2,746	392	484	134	366	4,122
Other Income (Expense)	(5,517)	4	(289)	(848)	940	(5,710)
Interest Expense	28,548	8,132	4,701	42	—	41,423
Income Tax Provision (Benefit)	30,940	(3,228)	21,538	1,402	(9,152)	41,500
Additions to Oil and Gas Properties	468,168	79,789	163	67,777	10,301	626,198
Total Assets	2,036,933	276,998	116,578	252,115	40,731	2,723,355

(1) See Note 7 "Transactions with Enron Corp. and Related Parties."
(2) Other includes China operations. See Note 7 "Transactions with Enron Corp. and Related Parties."
(3) Sales activity with a certain purchaser in the United States and Canada segments totaled approximately $98,100 of the consolidated Net Operating Revenues.

13. Other Income (Expense), Net

Other income (expense), net consisted of the following for the years ended December 31:

(In Thousands)	1999	1998	1997
Interest Income	**$ 1,037**	$ 1,147(1)	$ 4,122(1)
Financial Reserve Accruals(2)	**(1,972)**	(4,350)	—
Gain on Sale of Other Assets(3)	**59,647**	—	—
Gain on Share Exchange	**575,151**	—	—
International Asset Re-evaluation(4)	**(19,375)**	—	—
Contract Settlement	**—**	(610)	—
Litigation Provision	**—**	—	(5,800)
Other, Net	**(3,145)**	(987)	90
Total	**$ 611,343**	$ (4,800)	$ (1,588)

(1) Includes $102 in 1998 and $2,549 in 1997 from related parties.
(2) Pertains to provisions for doubtful accounts receivable associated with certain international activities.
(3) See Note 3 "Other Assets."
(4) Relates to anticipated costs of abandonment of certain international activity.

14. Price and Interest Rate Risk Management

Periodically, the Company 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 In 1999, no trading transactions were executed. Trading activities in 1998 included a revenue increase of $1.1 million related to change in market value of natural gas price swap options exercisable by a counterparty and partially offsetting "buy" price swap positions.

During 1995, the Company entered into a NYMEX-related natural gas price swap covering 73 trillion British thermal units ("TBtu") for the year ended December 31, 1996. This swap contained an option to extend the price swap covering 73 TBtu for each of the years 1997 and 1998 which was exercisable at one time prior to December 31, 1996. The 1996 price swap was closed in the first quarter of 1996. During 1996, this option was restructured into four options each exercisable, in total, at one time by the counterparty before December 31, 1996, 1997, 1998 and 1999 to purchase 37 TBtu of notional natural gas for each of the years 1997, 1998, 1999 and 2000 at an average fixed price of $1.98, $1.98, $1.93 and $1.93 per million British thermal units ("MMBtu"), respectively. The 1997 and 1998 options were subsequently restructured to be exercisable monthly at a price of $2.16 and $2.07 per MMBtu, respectively. These options cover notional volumes averaging 3 TBtu per month during 1997 and 1998. During the fourth quarter of 1996, the 1999 and 2000 options were terminated. In 1996, the Company entered into "buy" NYMEX-related natural gas price swap positions in the same notional quantities and maturities as are covered by the 1997 and 1998 options. The Company recognized a $1.1 million and $3.4 million revenue increase in 1998 and 1997, respectively, related to these trading activities.

The following table summarizes the estimated fair value of financial instruments held for trading purposes at yearend and the average during the year:

	Estimated Fair Values					
	1999(1)		1998(1)		1997(1)	
(In Millions)	Year-End	Average	Year-End	Average	Year-End	Average
Options Written	**$ —**	**$ —**	$ —	$ (5.1)	$ (10.5)	$ (13.7)
NYMEX-related Natural Gas Price Swaps	**—**	**—**	—	5.0	4.2	7.1

(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.

Interest Rate Swap Agreements and Foreign Currency Contracts At December 31, 1999 and 1998, a subsidiary of the Company and the Company are parties to offsetting foreign currency and interest rate swap agreements with an aggregate notional principal amount of $210 million. Such swap agreements are scheduled to terminate in 2001. At December 31, 1999 and 1998, the composite fair value of the agreements was not significant based upon termination values obtained from third parties. In November 1998, the Company 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 the Company's commercial paper, uncommitted credit facilities and affiliated borrowings. The Company anticipates having such borrowings outstanding of at least the notional amounts under the swap agreements during the term of the swap agreements. Under the agreements, the Company will pay interest based on fixed rates of approximately 4.96% and 5.01% and receive interest based on the three-month LIBOR calculated on the notional value of the swap agreements. These agreements are scheduled to terminate in November 2000. At December 31, 1999, the composite fair value of these agreements was $2.6 million.

Hedging Transactions With the objective of enhancing the certainty of future revenues, the Company from time to time enters into NYMEX-related commodity price swaps and costless collars. Using NYMEX-related commodity price swaps, the Company receives a fixed price for the respective commodity hedged and pays a floating market price, as defined for each transaction, to the counterparty at settlement.

At December 31, 1999, the Company had outstanding positions covering notional volumes of .5 million barrels ("MMBbl") of crude oil and condensate for 2000. The fair value of these positions was approximately $2 million negative. At December 31, 1999, the Company had closed positions covering notional volumes of approximately 4 TBtu of natural gas for each of the years 2000 through 2005. The Company also had closed positions covering 1.7 MMBbl of crude oil and condensate for the year 2000. At December 31, 1999, the aggregate deferred revenue reduction for 2000, 2001 and thereafter was approximately $12 million, $1 million and $5 million, respectively, and is classified as "Other Assets."

At December 31, 1998, the Company had outstanding positions covering notional volumes of .7 MMBbl of crude oil and condensate for 1999. The fair value of the positions was approximately $4 million. In 1998, the Company closed positions covering notional volumes of approximately 4 TBtu of natural gas for each of the years 1999 through 2005. The Company also recorded closed positions covering 2.2 MMBbl and 1.7 MMBbl of crude oil and condensate for the years 1999 and 2000, respectively. At December 31, 1998, the aggregate deferred revenue reduction for 1999, 2000 and thereafter was approximately $13 million, $12 million and $6 million, respectively, and is classified as "Other Assets".

The following table summarizes the estimated fair value of financial instruments and related transactions for non-trading activities at December 31, 1999 and 1998:

	1999		1998	
	Carrying Amount (In Millions)	Estimated Fair Value(1)	Carrying Amount (In Millions)	Estimated Fair Value(1)
Long-Term Debt(2)	**$ 990.3**	**$ 933.0**	$ 1,142.8	$ 1,141.0
Swap Agreements	**—**	**—**	4.2	4.1
NYMEX-Related Commodity Market Positions	**(18.0)**	**(20.3)**	(30.9)	(26.5)

(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 4 "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. The Company does not anticipate nonperformance by the other parties.

15. Concentration of Credit Risk

Substantially all of the Company's accounts receivable at December 31, 1999 and 1998 result from crude oil and natural gas sales and/or joint interest billings to affiliate and third party companies including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact the Company'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, the Company analyzes the entity's net worth, cash flows, earnings, and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred on receivables by the Company have been immaterial.

16. Accounting for Certain Long-Lived Assets

As a result of the change to the Company's portfolio of assets brought about by the Share Exchange (see Note 7 “Transactions with Enron Corp. and Related Parties”), the Company conducted a re-evaluation of its overall business. As a result of this re-evaluation, some of the Company's projects were no longer deemed central to its business. The Company recorded non-cash charges in connection with the impairment and/or the Company's decision to dispose of such projects of $133 million pre-tax ($89 million after-tax). In addition, the Company recorded charges of $15 million pre-tax ($10 million after-tax) pursuant to a change in the Company’s strategy related to certain offshore operations in the second quarter and an impairment of various North America properties in the fourth quarter 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 the Company'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 the Company'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.

17. 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. SFAS No. 133, as amended by SFAS No. 137, 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 the Company 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.

The Company has not yet quantified the impacts of adopting SFAS No. 133 on its financial statements and has not determined the timing of adoption. Based on the Company’s current level of derivative and hedging activities, the Company does not expect the impact of adoption to be material.

18. Subsequent Event

On February 14, 2000, the Company’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 the Company 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 amount 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 the Company'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 the Company's common stock, or if earlier, ten business days (or a later date determined by the Company'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 the Company's common stock with a market value of $180, based on the market price of the common stock prior to such acquisition. If the Company 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.

The Company'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 the Company has a stock split or declares a stock dividends of the Company's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of the Company'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.

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 the Company's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Company's share of future production from Canadian reserves to be materially different from that presented.

As a result of the re-evaluation of the Company's portfolio of assets following the Share Exchange, on November 12, 1999 senior management proposed to the Board of Directors ("the Board") of the Company to defer the development of the Big Piney Madison deep Paleozoic formation methane reserves in Wyoming for the foreseeable future. The basis for this recommendation was the substantial capital cost required to develop the project relative to the Company's anticipated spending budget for the next several years as well as the project's anticipated rate of return compared to other investment opportunities currently available to the Company. 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 the Company 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 the Company'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.

Estimates of proved and proved developed reserves at December 31, 1999, 1998 and 1997 were based on studies performed by the engineering staff of the Company for reserves in the United States, Canada, Trinidad, India and China (see Note 7 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, 1999, 1998 and 1997 covered producing areas containing 52%, 39% and 54%, respectively, of proved reserves, excluding deep Paleozoic methane reserves in 1998 and 1997, of the Company on a net-equivalent-cubic-feet-of-gas basis. D&M's opinions indicate that the estimates of proved reserves prepared by the Company'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 the Company. All reports by D&M were developed utilizing geological and engineering data provided by the Company.

No major discovery or other favorable or adverse event subsequent to December 31, 1999 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 the Company's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 1999, 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 the Company.

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, 1996	2,746.5[4]	320.9	370.2	3,437.6	199.6	—	3,637.2
Revisions of previous estimates	(50.8)	(1.5)	(0.4)	(52.7)	25.1	—	(27.6)
Purchases in place	60.0	67.6	—	127.6	—	—	127.6
Extensions, discoveries and other additions	275.9	37.8	—	313.7	253.5	7.7	574.9
Sales in place	(17.7)	(0.4)	—	(18.1)	—	—	(18.1)
Production	(229.1)	(37.0)	(41.0)	(307.1)	(6.6)	—	(313.7)
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**

(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, 1996	28,876	7,452	8,168	44,496	10,791	—	55,287
Revisions of previous estimates	3,515	225	(31)	3,709	19	—	3,728
Purchases in place	127	1,123	—	1,250	—	—	1,250
Extensions, discoveries and other additions	6,037	1,590	—	7,627	20,123	—	27,750
Sales in place	(1,683)	—	—	(1,683)	—	—	(1,683)
Production	(5,223)	(1,384)	(1,236)	(7,843)	(838)	—	(8,681)
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**
Bcf Equivalent (Bcfe)[1]							
Net proved reserves at December 31, 1996	2,920.1[4]	365.3	419.2	3,704.6	264.3	—	3,968.9
Revisions of previous estimates	(29.8)	(0.1)	(0.5)	(30.4)	25.2	—	(5.2)
Purchases in place	60.7	74.4	—	135.1	—	—	135.1
Extensions, discoveries and other additions	312.1	47.4	—	359.5	374.2	7.7	741.4
Sales in place	(27.7)	(0.4)	—	(28.1)	—	—	(28.1)
Production	(260.4)	(45.3)	(48.5)	(354.2)	(11.7)	—	(365.9)
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**

(Table continued on following page)

	United States	Canada	Trinidad	SUBTOTAL	India (2)	TOTAL
Net proved developed reserves at						
Natural Gas (Bcf)						
December 31, 1996	1,325.7	319.5	370.2	2,015.4	124.6	2,140.0
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**
Liquids (MBbl)(7)						
December 31, 1996	24,868	7,452	8,168	40,488	10,791	51,279
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**
Bcf Equivalents						
December 31, 1996	1,474.9	364.2	419.2	2,258.3	189.3	2,447.6
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**

(1) Billion cubic feet or billion cubic feet equivalent, as applicable.
(2) See Note 7 "Transactions with Enron Corp. and Related Parties."
(3) Other includes proved reserves for China operations only, none of which are proved developed. See Note 7 "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 removal of the 1,180 Bcf of proved undeveloped methane reserves mentioned in (4) as a result of the Company'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 the Company's natural gas and crude oil producing activities at December 31, 1999 and 1998:

		1998		
	1999	North America and Trinidad	Other	Total
Proved Properties	**$ 4,459,727**	$ 4,352,247	$ 257,643	$ 4,609,890
Unproved Properties	**143,013**	176,420	28,115	204,535
Total	**4,602,740**	4,528,667	285,758	4,814,425
Accumulated depreciation, depletion and amortization	**(2,267,812)**	(2,120,520)	(17,542)	(2,138,062)
Net capitalized costs	**$ 2,334,928**	$ 2,408,147	$ 268,216	$ 2,676,363

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 the Company's oil and gas activities for the years ended December 31:

	United States	Canada	Trinidad	Other	SUBTOTAL	India[1]	China[1]	TOTAL
1999								
Acquisition Costs of Properties								
Unproved	**$ 18,964**	**$ 2,276**	**$ —**	**$ —**	**$ 21,240**	**$ —**	**$ —**	**$ 21,240**
Proved	**22,092**	**20,838**	**—**	**—**	**42,930**	**—**	**—**	**42,930**
Total	**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	**240,590**	**38,832**	**5,615**	**—**	**285,037**	**23,820**	**8,010**	**316,867**
Total	**$ 346,716**	**$ 68,462**	**$ 14,040**	**$ 4,350**	**$ 433,568**	**$ 24,903**	**$ 9,024**	**$ 467,495**
1998								
Acquisition Costs of Properties								
Unproved	$ 32,925	$ 3,545	$ —	$ —	$ 36,470	$ —	$ —	$ 36,470
Proved	198,006	12,896	—	—	210,902	—	—	210,902
Total	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	297,904	27,822	6,157	12,016	343,899	46,657	4,532	395,088
Total	$ 611,083	$ 56,638	$ 21,374	$ 36,199	$ 725,294	$ 47,935	$ 5,814	$ 779,043
1997								
Acquisition Costs of Properties								
Unproved	$ 69,258	$ 7,700	$ —	$ 35	$ 76,993	$ —	$ 200	$ 77,193
Proved	42,386	38,949	—	28	81,363	—	—	81,363
Total	111,644	46,649	—	63	158,356	—	200	158,556
Exploration Costs	74,360	8,279	1,344	11,407	95,390	965	4,528	100,883
Development Costs	333,093	30,856	163	9,185	373,297	67,777	684	441,758
Total	$ 519,097	$ 85,784	$ 1,507	$ 20,655	$ 627,043	$ 68,742	$ 5,412	$ 701,197

(1) See Note 7 "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
1999							
Operating Revenues							
Trade	**$ 492,308**	**$ 83,503**	**$ 55,900**	**$ 631,711**	**$ 51,554**	**$ 39**	**$ 683,304**
Associated Companies	**121,790**	**11,161**	**—**	**132,951**	**—**	**—**	**132,951**
Gains on Sales of Reserves and Related Assets	**2,254**	**75**	**—**	**2,329**	**—**	**(7,931)**	**(5,602)**
Total	**616,352**	**94,739**	**55,900**	**766,991**	**51,554**	**(7,892)**	**810,653**
Exploration Expenses, including Dry Hole	**49,181**	**5,122**	**5,865**	**60,168**	**1,083**	**3,415**	**64,666**
Production Costs	**93,137**	**21,620**	**8,322**	**123,079**	**11,070**	**2,334**	**136,483**
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	**74,115**	**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	$ 431,943	$ 53,485	$ 66,967	$ 552,395	$ 72,826	$ 52	$ 625,273
Associated Companies	117,719	15,132	—	132,851	—	—	132,851
Gains on Sales of Reserves and Related Assets	29,268	(15)	—	29,253	—	(3,658)	25,595
Total	578,930	68,602	66,967	714,499	72,826	(3,606)	783,719
Exploration Expenses, including Dry Hole	63,875	7,496	2,027	73,398	1,278	14,015	88,691
Production Costs	98,909	19,715	7,361	125,985	13,617	3,666	143,268
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
1997							
Operating Revenues							
Trade	$ 448,824	$ 58,712	$ 66,000	$ 573,536	$ 35,332	$ 21	$ 608,889
Associated Companies	206,738	15,280	—	222,018	—	2	222,020
Gains on Sales of Reserves and Related Assets	4,464	(13)	—	4,451	—	4,836	9,287
Total	660,026	73,979	66,000	800,005	35,332	4,859	840,196
Exploration Expenses, including Dry Hole	50,930	5,995	1,344	58,269	965	15,765	74,999
Production Costs	106,395	20,073	12,256	138,724	10,505	75	149,304
Impairment of Unproved Oil and Gas Properties	24,229	2,643	—	26,872	—	341	27,213
Depreciation, Depletion and Amortization	238,765	23,116	11,032	272,913	3,716	901	277,530
Income (Loss) before Income Taxes	239,707	22,152	41,368	303,227	20,146	(12,223)	311,150
Income Tax Provision (Benefit)	69,252	8,130	22,752	100,134	9,670	(252)	109,552
Results of Operations	$ 170,455	$ 14,022	$ 18,616	$ 203,093	$ 10,476	$ (11,971)	$ 201,598

(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, 1999. 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 7 "Transactions with Enron Corp. and Related Parties."

(3) Other includes China and other international operations. See Note 7 "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 the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company 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 the Company.

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 the Company's crude oil and natural gas reserves for the years ended December 31:

	United States	Canada	Trinidad	SUBTOTAL	India(1)	Other(2)	TOTAL
1999							
Future cash inflows	**$ 4,653,014**	**$ 1,338,034**	**$ 1,455,951**	**$ 7,446,999**	**$ —**	**$ —**	**$ 7,446,999**
Future production costs	**(1,277,485)**	**(477,303)**	**(486,902)**	**(2,241,690)**	**—**	**—**	**(2,241,690)**
Future development costs	**(175,039)**	**(49,005)**	**(158,778)**	**(382,822)**	**—**	**—**	**(382,822)**
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	$ 950,151	$ 1,210,060	$ 7,631,332	$ 2,384,459	$ 179,329	$ 10,195,120
Future production costs	(1,280,875)	(319,938)	(347,431)	(1,948,244)	(556,609)	(127,039)	(2,631,892)
Future development costs	(316,175)	(42,252)	(161,424)	(519,851)	(392,546)	(11,325)	(923,722)
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(3)	$ 306,318	$ 237,795	$ 2,114,660	$ 386,293	$ 19,961	$ 2,520,914
1997							
Future cash inflows	$ 5,186,755	$ 814,195	$ 532,318	$ 6,533,268	$ 1,633,199	$ 13,862	$ 8,180,329
Future production costs	(1,138,401)	(302,965)	(106,999)	(1,548,365)	(422,474)	(3,587)	(1,974,426)
Future development costs	(313,463)	(19,610)	(400)	(333,473)	(102,014)	(1,814)	(437,301)
Future net cash flows before income taxes	3,734,891	491,620	424,919	4,651,430	1,108,711	8,461	5,768,602
Future income taxes	(887,521)	(92,927)	(215,344)	(1,195,792)	(501,109)	(779)	(1,697,680)
Future net cash flows	2,847,370	398,693	209,575	3,455,638	607,602	7,682	4,070,922
Discount to present value at 10% annual rate	(1,297,651)	(121,381)	(61,656)	(1,480,688)	(287,874)	(1,906)	(1,770,468)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,549,719(3)	$ 277,312	$ 147,919	$ 1,974,950	$ 319,728	$ 5,776	$ 2,300,454

(1) See Note 7 "Transactions with Enron Corp. and Related Parties."
(2) Other includes the standardized measure for proved reserves for China operations only. See Note 7 "Transactions with Enron Corp. and Related Parties."
(3) Includes approximately $55,316 and $100,294 in 1997 and 1998, respectively, related to the reserves in the Big Piney deep Paleozoic formations, which were removed from proved reserves in 1999.

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, 1999.

	United States	Canada	Trinidad	SUBTOTAL	India[1]	Other[2]	TOTAL
December 31, 1996	$ 2,491,769[3]	$ 225,758	$ 156,838	$ 2,874,365	$ 194,185	$ —	$ 3,068,550
Sales and transfers of oil and gas produced, net of production costs	(518,594)	(53,919)	(53,744)	(626,257)	(24,827)	—	(651,084)
Net changes in prices and production costs	(1,664,174)	(19,784)	4,730	(1,679,228)	(34,611)	—	(1,713,839)
Extensions, discoveries, additions and improved recovery net of related costs	374,283	37,533	—	411,816	257,256	5,616	674,688
Development costs incurred	52,300	1,900	—	54,200	—	—	54,200
Revisions of estimated development costs	3,681	4,345	1,188	9,214	(33,210)	—	(23,996)
Revisions of previous quantity estimates	(17,257)	(101)	(442)	(17,800)	26,696	—	8,896
Accretion of discount	327,724	26,287	30,956	384,967	31,669	—	416,636
Net change in income taxes	605,769	11,097	12,734	629,600	(90,729)	160	539,031
Purchases of reserves in place	43,882	52,911	—	96,793	—	—	96,793
Sales of reserves in place	(28,589)	(379)	—	(28,968)	—	—	(28,968)
Changes in timing and other	(121,075)	(8,336)	(4,341)	(133,752)	(6,701)	—	(140,453)
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)	10,891	(36,730)	(59,648)	(103,097)	(6,961)	(169,706)
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)	690	(11,410)	(37,331)	(66,128)	(3,233)	(106,692)
Revisions of previous quantity estimates	(35,216)	(4,137)	(1,142)	(40,495)	36,877	—	(3,618)
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)	(20,763)	4,598	(205,992)	(56,954)	(2,613)	(265,559)
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	76,478	76,381	418,805	—	—	418,805
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	(1,127)	8,178	140,792	—	—	140,792
Revisions of previous quantity estimates	(163,423)[4]	(506)	2,051	(161,878)	—	—	(161,878)
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)	13,365	(11,333)	(73,740)	—	—	(73,740)
December 31, 1999	**$ 1,727,232**	**$ 377,891**	**$ 288,933**	**$ 2,394,056**	**$ —**	**$ —**	**$ 2,394,056**

(1) See Note 7 "Transactions with Enron Corp. and Related Parties."

(2) Other includes China operations only. See Note 7 "Transactions with Enron Corp. and Related Parties."

(3) Includes approximately $222,228, $55,316 and $100,294, in 1996, 1997 and 1998, respectively, related to the reserves in the Big Piney deep Paleozoic formations.

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

Unaudited Quarterly Financial Information

(In Thousands, Except Per Share Amounts)	Quarter Ended March 31	June 30	Sept. 30	Dec. 31
1999				
Net Operating Revenues	**$ 158,954**	**$ 187,195**	**$ 226,780**	**$ 228,477**
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**
Net Income per Share Available to Common				
Basic	**$ .03**	**$ .13**	**$ 3.75**	**$ .25**
Diluted	**$ .03**	**$ .13**	**$ 3.68**	**$ .25**
Average Number of Common Shares				
Basic	**153,733**	**153,825**	**136,750**	**119,169**
Diluted	**154,615**	**155,271**	**139,204**	**120,226**
1998				
Net Operating Revenues	$ 199,831	$ 183,307	$ 191,262	$ 194,788
Operating Income	$ 38,286	$ 32,669	$ 19,199	$ 23,507
Income before Income Taxes	28,206	22,173	3,969	5,934
Income Tax Provision (Benefit)	1,201	8,916	(1,975)	(4,031)
Net Income	$ 27,005	$ 13,257	$ 5,944	$ 9,965
Net Income per Share Available to Common				
Basic	$ .17	$ .09	$ .04	$ .06
Diluted	$ .17	$ .09	$ .04	$ .06
Average Number of Common Shares				
Basic	154,736	154,857	154,083	153,702
Diluted	155,522	155,770	154,409	154,516
1997				
Net Operating Revenues	$ 180,651	$ 171,753	$ 193,120	$ 237,977
Operating Income	$ 41,170	$ 28,619	$ 48,757	$ 74,229
Income before Income Taxes	37,311	24,111	40,975	61,073
Income Tax Provision (Benefit)	14,246	(460)	9,802	17,912
Net Income	$ 23,065	$ 24,571	$ 31,173	$ 43,161
Net Income per Share Available to Common				
Basic	$ .15	$ .16	$ .20	$ .28
Diluted	$ .14	$ .16	$ .20	$ .28
Average Number of Common Shares				
Basic	158,866	157,489	157,072	156,076
Diluted	159,790	157,950	158,049	156,808

Selected Financial Data

(In Thousands, Except Per Share Amounts)	Year Ended December 31, 1999	1998	1997	1996	1995
Statement of Income Data:					
Net operating revenues	**$ 801,406**	$ 769,188	$ 783,501	$ 730,648	$ 648,702
Operating expenses					
Lease and well	**91,540**	98,868	96,064	76,618	69,463
Exploration costs	**52,773**	65,940	57,696	55,009	42,044
Dry hole costs	**11,893**	22,751	17,303	13,193	12,911
Impairment of unproved oil and gas properties	**31,608**	32,076	27,213	21,226	23,715
Depreciation, depletion and amortization	**459,877**(1)	315,106	278,179	251,278	216,047
General and administrative	**82,857**	69,010	54,415	56,405	56,626
Taxes other than income	**52,670**	51,776	59,856	48,089	32,587
Total	**783,218**	655,527	590,726	521,818	453,393
Operating income	**18,188**	113,661	192,775	208,830	195,309
Other income (expense), net	**611,343**(2)	(4,800)	(1,588)	(5,007)	669
Interest expense (net of interest capitalized)	**61,819**	48,579	27,717	12,861	11,924
Income before income taxes	**567,712**	60,282	163,470	190,962	184,054
Income tax provision (benefit)(3)	**(1,382)**	4,111(4)	41,500(5)	50,954(6)	41,936(7)
Net income	**$ 569,094**	$ 56,171	$ 121,970	$ 140,008	$ 142,118
Net income per share available to common					
Basic	**$ 4.04**	$ .36	$ .78	$ .88	$ .89
Diluted	**$ 3.99**	$ .36	$ .77	$ .87	$ .88
Average number of common shares					
Basic	**140,869**	154,345	157,376	159,853	159,917
Diluted	**142,352**	155,054	158,160	161,525	161,132

(In Thousands)	At December 31, 1999	1998	1997	1996	1995
Balance Sheet Data:					
Oil and gas properties - net	**$2,334,928**	$ 2,676,363	$ 2,387,207	$ 2,099,589	$ 1,881,545
Total assets	**2,610,793**	3,018,095	2,723,355	2,458,353	2,147,258
Long-term debt					
Trade	**990,306**	942,779	548,775	466,089	147,559
Affiliate	**—**	200,000	192,500	—	141,520
Deferred revenue	**—**	4,198	39,918	56,383	205,453
Shareholders' equity	**1,129,611**	1,280,304	1,281,049	1,265,090	1,163,659

(1) See Note 16 to the Consolidated Financial Statements.
(2) See Note 7 to the Consolidated Financial Statements.
(3) Includes benefits of approximately $8 million, $12 million, $12 million, $16 million and $22 million in 1999, 1998, 1997, 1996 and 1995 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 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.
(7) Includes a benefit of approximately $14 million associated with the successful resolution on audit of federal income taxes for certain prior years.

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Former Chairman,
President and CEO
The Superior Oil Company

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

Edward Randall, III [2]
Houston, Texas
Investments

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

Frank G. Wisner [3]
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.
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Counsel

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Financial Officer

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Senior Vice President, Law

Lawrence E. Fenwick
Senior Vice President and
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Tax Counsel

Maire A. Baldwin
Investor Relations

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

Shareholder Information

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Common Stock Exchange Listing:
New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at
December 31, 1999: 119,104,554

Principal Transfer Agent
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Additional Information
The Annual Meeting of Shareholders will be held at 2 p.m. CDT in the La Salle "A" Ballroom of the Doubletree Hotel at Allen Center, 400 Dallas Street, Houston, Texas on Tuesday, May 9, 2000. 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 contact Maire A. Baldwin, Investor Relations (713) 651-6EOG.

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
CNC	Caribbean Nitrogen Limited
$/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
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
MMcf/d	Million cubic feet per day
MMcfe/d	Million cubic feet equivalent per day
NGC	National Gas Company of Trinidad and Tobago Limited
SECC	South East Coast Consortium (Trinidad)
Tcf	Trillion cubic feet
Tcfe	Trillion cubic feet equivalent

Forward Looking Statement
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. Although EOG Resources believes that its expectations are based on reasonable assumptions, it can give no assurance that such expectations will be achieved. Important factors that could cause actual results to differ materially from those in the forward looking statements herein include, but are not limited to, the timing and extent of changes in reserve quantities and commodity prices for crude oil, natural gas and related products and interest rates, the extent of EOG Resources' success in discovering, developing, producing and marketing reserves and in acquiring oil and gas properties, uncertainties and changes associated with international projects and operations including reserve estimates, markets, contract terms, construction, financing availability, operating costs, and political developments around the world, and conditions of the capital and equity markets during the periods covered by the forward looking statements.

For helping make it all possible, a special thanks to: Latiff Abdool, Ismael Abila, Rocio Abrego, Linda Acosta, Tammy Adair, Ronnie Adams, Melissa Albert, William Albrecht, Gail Albritton, Joseph Alexander, Kenneth Allen, Robert Apperson, Kerry Archibald, Blaine Ardelian, Rene Argueta, Ralph Armentrout, Robert Armstrong, Paul Arnott, Rose Baggerly, Maire Baldwin, Jerry Ball, John Ball, Bradley Bangle, Jimmy Banks, Bijay Banthia, Brian Baptiste, Judy Barlow, Kelley Barnett, Emilio Barrera, Anthony Barrett, Curt Bateman, Dale Bawol, Ana Beasley, James Beavers, John Becker, Barbara Belcher, April Bell, Douglas Bellis, Steven Bennett, Stephen Benoit, Sandeep Bhakhri, Jerry Biggs, Blaine Bischoff, Brad Blackwood, Melanie Blazek, Dana Blevins, Mark Bloom, Stanley Blundell, Kenneth Boedeker, Kelly Bonogofski, Stewart Bosch, Tim Bosch, Deidra Bourland, Danny Bowthorpe, Ben Boyd, Dennis Brabec, Diane Bradley, Tom Bradley, Joy Branham, Cheryl Brashear, James Breimayer, Judith Bretz, Tammy 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