EOG RESOURCES INC
Form 10-K
February 28, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 1-9743

EOG RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	47-0684736 (I.R.S. Employer Identification No.)

333 Clay Street, Suite 4200, Houston, Texas 77002-7361

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: 713-651-7000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of February 16, 2007 and as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of February 16, 2007: $16,347,875,983 and as of June 30, 2006: $16,818,631,746.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $0.01 per share, on February 16, 2007, Shares Outstanding: 243,998,149.

Documents incorporated by reference. Portions of the following document are incorporated by reference into the indicated parts of this report: Proxy Statement for the April 24, 2007 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2006 (Proxy Statement) - Part III.

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PART I

ITEM 1. *Business*

General

EOG Resources, Inc. (EOG), a Delaware corporation organized in 1985, together with its subsidiaries, explores for, develops, produces and markets natural gas and crude oil primarily in major producing basins in the United States of America (United States), Canada, offshore Trinidad, the United Kingdom North Sea and, from time to time, select other international areas. EOG's principal producing areas are further described in "Exploration and Production" below. EOG's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports are made available, free of charge, through its website, as soon as reasonably practicable after such reports have been filed with the Securities and Exchange Commission (SEC). EOG's website address is http://www.eogresources.com.

At December 31, 2006, EOG's total estimated net proved reserves were 6,802 billion cubic feet equivalent (Bcfe), of which 6,095 billion cubic feet (Bcf) were natural gas reserves and 118 million barrels (MMBbl), or 707 Bcfe, were crude oil, condensate and natural gas liquids reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 60% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 20% in Canada and 20% in Trinidad. As of December 31, 2006, EOG employed approximately 1,570 persons, including foreign national employees.

EOG's business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis. EOG focuses its drilling activity toward natural gas deliverability in addition to natural gas reserve replacement and to a lesser extent crude oil exploration and exploitation. EOG focuses on the cost-effective utilization of advances in technology associated with the gathering, processing and interpretation of three-dimensional (3-D) seismic data, the development of reservoir simulation models, the use of new and/or improved drill bits, mud motors and mud additives, and formation logging techniques and reservoir fracturing methods. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks associated with all aspects of oil and gas exploration, development and exploitation. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low cost reserves. EOG also makes select tactical acquisitions that result in additional economies of scale or land positions with significant additional prospects. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG's strategy.

With respect to information on EOG's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by EOG's working interest in the wells or acreage.

Business Segments

EOG's operations are all natural gas and crude oil exploration and production related.

Exploration and Production

United States and Canada Operations

EOG's operations are focused on most of the productive basins in the United States and Canada.

At December 31, 2006, 88% of EOG's net proved United States and Canada reserves (on a natural gas equivalent basis) were natural gas and 12% were crude oil, condensate and natural gas liquids. Substantial portions of these reserves are in long-lived fields with well-established production characteristics. EOG believes that opportunities exist to increase production through continued development in and around many of these fields and through application of new processes and technologies. EOG also maintains an active exploration program designed to extend fields and add new trends to its broad portfolio. The following is a summary of significant developments during 2006 and certain 2007 plans for EOG's United States and Canada operations.

United States.

During 2006, EOG substantially increased drilling activity, acreage position, reserve potential and production in the Fort Worth Basin Barnett Shale play (Fort Worth Barnett). The net average production from the Fort Worth Barnett for 2006 was 145 million cubic feet per day (MMcfd) of natural gas and 300 barrels per day (Bbld)

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of crude oil, condensate and natural gas liquids. EOG drilled 205 net Fort Worth Barnett wells during 2006 and grew production to over 200 MMcfd, net by year-end 2006. During the year, EOG leased more than 100,000 additional net acres and increased EOG's total leasehold to greater than 600,000 net acres. EOG will substantially increase drilling activity in the Forth Worth Barnett during 2007 with plans to drill approximately 380 gross wells and exit the year with over 300 MMcfd net production. EOG continues to generate new opportunities in the Fort Worth Barnett which EOG expects will add significant future reserve and production potential.

The Upper Gulf Coast continued to be a growth area for EOG where 2006 net production averaged 117 MMcfd of natural gas and 3.5 thousand barrels per day (MBbld) of crude oil, condensate and natural gas liquids. EOG drilled 60 net wells with 30 net wells in the Cotton Valley and Travis Peak development programs at the Sligo, Minden, Carthage and Appleby Fields. North Louisiana development activity included five net wells at Driscoll Mountain in the expanded Cotton Valley and 10 horizontal producers in Spider Field. EOG continues its growth in Mississippi where 13 successful net wells were drilled in 2006 in the Hosston play in South Williamsburg. EOG is currently one of the largest natural gas producers in Mississippi. EOG will continue its growth in East Texas, Louisiana and Mississippi with tests of several high potential impact new projects in 2007.

In the Permian Basin, EOG drilled 30 net horizontal gas wells in 2006 in the New Mexico Wolfcamp play. EOG has over 40,000 net acres in the play and plans to drill approximately 33 net wells in 2007. EOG has identified approximately 100 drilling locations in this play. Significant drilling and completion improvements have resulted in cost reductions, as well as quick spud-to-sales cycle times for these wells. This activity was complemented by a number of successful wells in the Permo-Penn Carbonate, Bone Spring Carbonate and Horizontal Bone Spring. EOG drilled 61 net wells in 2006, and net production averaged 87 MMcfd of natural gas and 7.1 MBbld of crude oil, condensate and natural gas liquids. Several additional horizontal plays, which could set up multiple drilling locations, will be tested in 2007 on over 20,000 acres controlled by EOG.

EOG increased drilling activity within its core areas of the Rocky Mountain area, drilling 179 net wells during 2006, including 84 net wells in the Uinta Basin, Utah, 40 net wells in the LaBarge Platform, Wyoming, 34 net wells in the Moxa Arch area, Wyoming, and seven net wells in the Williston Basin. The net average daily production for 2006 from the Rocky Mountain area was 165 MMcfd of natural gas and 8.6 MBbld of crude oil, condensate and natural gas liquids. EOG expects to continue increasing drilling activity in these core areas during 2007, while maintaining an active exploration and delineation program in other areas in Utah, Wyoming and North Dakota.

In the Mid-Continent area, EOG drilled 117 net wells in its core areas in 2006, most notably the Hugoton-Deep play in the Oklahoma Panhandle and the Cleveland Horizontal play in the Texas Panhandle. The net average production for 2006 was 74 MMcfd of natural gas and 2.4 MBbld of crude oil and condensate. In the Hugoton-Deep play, EOG shifted its prospecting into Southwest Kansas and was successful in finding several new Morrow plays. Net production from this area increased from 25 MMcfd in the beginning of 2006 to over 50 MMcfd by year-end. Nine years remain on the 900,000 acre, 10-year joint venture with Anadarko Petroleum Company. In the Cleveland Horizontal play, EOG drilled 28 net wells in 2006, bringing its total to 125 net wells drilled since 2003. EOG plans to continue exploiting these two core growth areas in 2007, while pursuing other exploration prospects throughout the Mid-Continent area.

EOG had another successful year in South Texas, drilling 84 net wells in 2006. South Texas onshore net production averaged 185 MMcfd of natural gas and 6.3 MBbld of crude oil, condensate and natural gas liquids during 2006. The activity was focused in Webb, Zapata, San Patricio, Duval, and Starr counties, where EOG drilled successful wells in the Lobo, Roleta, Reklaw, Frio, and Wilcox trends. EOG's application of horizontal drilling and completion technology in the Wilcox trend has resulted in new opportunities for this mature play. EOG added significant lease positions and 3-D seismic in 2006 to sustain a long-term drilling program.

During 2006, EOG participated in two discoveries in the Gulf of Mexico. In the High Island area, one well is producing and another well is expected to be on sales during the first quarter of 2007. A development well is currently being drilled in High Island Block 130 and is expected to be completed by March 2007. Net production from these three wells is expected to be 10 MMcfd by mid-2007. Drilling and completion operations for a deepwater project are underway, and first production is projected for early 2008. At least two additional exploratory projects are planned for the Gulf of Mexico in 2007.

In 2006, EOG drilled 68 net wells in the Appalachian Basin. Net production averaged 19 MMcfd of natural gas and 60 Bbld of crude oil and condensate. EOG is planning a similar drilling program in 2007. The majority of the wells will be drilled in the shallow Devonian and 10 net wells are planned for the Marcellus Shale. The Marcellus wells will be drilled in Pennsylvania to evaluate EOG's acreage in the joint venture with Seneca Resources Corporation.

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At December 31, 2006, EOG held approximately 3,184,000 net undeveloped acres in the United States.

Canada

. In Canada, EOG conducts operations through its subsidiary, EOG Resources Canada Inc. (EOGRC), from offices in Calgary, Alberta. During 2006, EOGRC continued its successful shallow gas strategy in Western Canada, drilling a total of 1,330 net wells. The 2006 shallow natural gas drilling program included 128 net Horseshoe Canyon coalbed methane wells. EOGRC participated in two exploratory wells in the Northwest Territories in 2006, resulting in a new pool discovery and a confirmation of an existing discovery made in 2004. EOGRC's net production during 2006 averaged 226 MMcfd of natural gas and 3.3 MBbld of crude oil, condensate and natural gas liquids. Key producing areas are the Southeast Alberta/Southwest Saskatchewan shallow natural gas trends including the Drumheller, Twining and Halkirk areas, the Pembina/Highvale area of Central Alberta, the Grand Prairie/Wapiti area of Northwest Alberta and the Waskada area in Southwest Manitoba. EOGRC plans to drill approximately 1,000 net wells in these areas during 2007.

At December 31, 2006, EOGRC held approximately 1,568,000 net undeveloped acres in Canada.

Operations Outside the United States and Canada

EOG has operations offshore Trinidad and in the United Kingdom North Sea, and is evaluating additional exploration, development and exploitation opportunities in Trinidad, the United Kingdom and other international areas.

Trinidad

. In November 1992, EOG, through its subsidiary, EOG Resources Trinidad Limited (EOGRT), acquired an exploration and production license in the South East Coast Consortium (SECC) Block offshore Trinidad. EOG currently has an 80% working interest in the Block, except the Deep Ibis prospect in which EOG's working interest decreased as a result of a farm-out agreement with BP Trinidad Tobago LLC (BP). The SECC Deep Ibis well spudded in April 2006, was drilled to a depth of approximately 19,000 feet and was abandoned and classified as a dry hole in the third quarter of 2006. BP paid the entire cost for drilling the exploratory well. The Kiskadee, Ibis and Parula fields have been developed and are being produced. In 2006, EOG continued the development of the Oilbird field and expects initial production in the second quarter of 2007. Effective September 1, 2006, the Oilbird Field Unitization Agreement was executed as the Oilbird field straddles the SECC Block and the U(b) Block. The license covering the SECC Block will expire in December 2029.

In July 1996, EOG, through its subsidiary, EOG Resources Trinidad-U(a) Block Limited, signed a production sharing contract with the Government of Trinidad and Tobago for the Modified U(a) Block. EOG holds a 100% working interest in this block. The Osprey field was discovered in 1998 and commenced production in 2002.

Surplus processing and transportation capacity at the Pelican field facilities (owned and operated by a subsidiary of the other participants in the SECC Block) is being used to process and transport EOG's natural gas production from the SECC Block and all of its crude oil and condensate production from both the SECC and Modified U(a) Blocks. Crude oil and condensate from EOG's Trinidad operations are being sold to the Petroleum Company of Trinidad and Tobago.

In April 2002, EOG, through its subsidiary, EOG Resources Trinidad-LRL Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for the Lower Reverse "L" (LRL) Block which is adjacent to the SECC Block. EOG holds a 100% working interest in the LRL Block. In the fourth quarter of 2003, EOG drilled the first exploratory well, LRL #1, on this block. The well was determined to be non-commercial. In November 2004, EOG drilled the LRL #2 well which encountered approximately 130 feet of net pay. EOG is currently evaluating development options for the LRL #2 discovery. In December 2004, the LRL #3 exploratory well was drilled and determined to be a dry hole.

In October 2002, EOG, through its subsidiary, EOG Resources Trinidad U(b) Block Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for the Modified U(b) Block which is also adjacent to the SECC Block. EOG holds a 55% working interest in and operates the Modified U(b) Block. Primera Oil & Gas Ltd., a Trinidadian company, holds the remaining 45% working interest. In September 2004, EOG drilled the first exploratory well on this block, and the well was determined to be non-commercial. Effective September 1, 2006, the Oilbird Field Unitization Agreement was executed as the Oilbird field straddles the SECC Block and the U(b) Block.

In July 2005, EOG, through its subsidiary, EOG Resources Trinidad Block 4(a) Unlimited, signed a production sharing contract with the Government of Trinidad and Tobago for Block 4(a). EOG, as the operator, holds a 90% working interest in Block 4(a). Primera Block 4(a) Limited, a Trinidadian company, holds the remaining 10% working interest. In the first quarter of 2006, two successful wells were drilled on Block 4(a). EOG's subsidiary has obtained approval to develop the discovery and has executed a term sheet with the National Gas Company of Trinidad and Tobago (NGC) for the sale of the gas.

Natural gas from EOG's Trinidad operations is being sold to the NGC under the following arrangements:

- Under a take-or-pay contract expiring in December 2018, natural gas is delivered to NGC for resale to Trinidad local markets. During 2006, EOG delivered net average production of 150 MMcfd of natural gas under this agreement. Prices are partially dependent on Caribbean ammonia index prices and methanol prices.

- Under a take-or-pay contract expiring in 2017, EOG delivers to NGC approximately 60 MMcfd, gross, of natural gas which is resold to an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited (CNCL). During 2006, 24 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC. The plant commenced production in June 2002. EOGRT owns a 12% equity interest in CNCL. At December 31, 2006, EOGRT's investment in CNCL was $19 million. At December 31, 2006, CNCL had a long-term debt balance of $142 million, which is non-recourse to CNCL's shareholders. As part of the financing for CNCL, the shareholders have entered into a post-completion deficiency loan agreement with CNCL to fund the costs of operations, payment of principal and interest to the principal creditor and other cash deficiencies of CNCL up to $30 million, approximately $4 million of which is net to EOGRT's interest. The shareholders' agreement governing CNCL requires the consent of the holders of 90% or more of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOGRT is able to exercise significant influence over the operating and financial policies of CNCL and therefore, EOG accounts for the investment using the equity method. During 2006, EOG recognized equity income of $8 million and received cash dividends of $7 million from CNCL.

- Under a fifteen-year take-or-pay contract expiring in 2019, EOG delivers to NGC approximately 60 MMcfd, gross, of natural gas which is resold to an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited (N2000). During 2006, 25 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC. The plant commenced production in August 2004. EOG's subsidiary, EOG Resources NITRO2000 Ltd. (EOGNitro2000), owns a 10% equity interest in N2000. At December 31, 2006, EOGNitro2000's investment in N2000 was $17 million. At December 31, 2006, N2000 had a long-term debt balance of $166 million, which is non-recourse to N2000's shareholders. As part of the loan agreement for the N2000 financing, affiliates of the shareholders have entered into a post-completion deficiency loan agreement with N2000 to fund the costs of operations, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $30 million, approximately $3 million of which is to be provided by the immediate parent company of EOGNitro2000. The shareholders' agreement governing N2000 requires the consent of the holders of 100% of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOGNitro2000 is able to exercise significant influence over the operating and financial policies of N2000 and therefore, EOG accounts for the investment using the equity method. During 2006, EOG recognized equity income of $10 million and received cash dividends of $9 million from N2000.

- Under a fifteen-year natural gas contract signed in January 2004, EOG is currently supplying approximately 100 MMcfd, gross, of natural gas to NGC, which is then being resold by NGC to a methanol plant located in Point Lisas, Trinidad. EOG has no investment in the methanol plant which became operational in September 2005. Under this natural gas contract, EOG expects to ultimately supply approximately 100 MMcfd, gross, (73 MMcfd, net to EOG, based on current pricing and operating assumptions) for the first four years of the contract term, beginning in 2005, and approximately 130 MMcfd, gross, (90 MMcfd, net to EOG, based on current pricing and operating assumptions) for the remaining term of the eleven-year contract. During 2006, 49 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC.

- In February 2005, EOGRT executed a twenty-year take-or-pay contract with NGC LNG (Train 4) Limited, a subsidiary of NGC, for the supply of 30 MMcfd, gross, (13 MMcfd, net to EOG, based on current pricing and operating assumptions) of natural gas for use in the Atlantic LNG Train 4 (ALNG) plant in Point Fortin, Trinidad. EOG has no investment in the ALNG plant. The plant commenced its start-up phase and began taking gas during December 2005. The plant remained in the start-up phase through December 2006. During 2006, 17 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC. The ALNG plant has not yet reached commercial status.

In 2006, EOG's average net production from Trinidad was 264 MMcfd of natural gas and 4.8 MBbld of crude oil and condensate.

At December 31, 2006, EOG held approximately 209,000 net undeveloped acres in Trinidad.

United Kingdom.

In 2002, EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), acquired a 25% non-operating working interest in a portion of Block 49/16, located in the Southern Gas Basin of the North Sea. In August 2004, production commenced in the Valkyrie field in the Southern Gas Basin.

In 2003, EOGUK acquired a 30% non-operating working interest in a portion of Blocks 53/1 and 53/2. These blocks are also located in the Southern Gas Basin of the North Sea. Since November 2003, three successful exploratory wells have been drilled in the Arthur field, with production commencing in January 2005.

During the fourth quarter of 2006, EOG participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. The Columbus well was a farm-in opportunity and its future appraisal and development is currently being evaluated.

In 2006, EOG delivered net average production of 30 MMcfd of natural gas in the United Kingdom.

At December 31, 2006, EOG held approximately 352,000 net undeveloped acres in the United Kingdom.

Other International. EOG continues to evaluate other select natural gas and crude oil opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous natural gas and crude oil reserves have been identified.

Marketing

Wellhead Marketing.

EOG's United States and Canada wellhead natural gas production is currently being sold on the spot market and under long-term natural gas contracts at market-responsive prices. In many instances, the long-term contract prices closely approximate the prices received for natural gas being sold on the spot market. In 2006, a large majority of the wellhead natural gas volumes from Trinidad were sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes were sold under a contract at prices partially dependent on the United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad will remain the same in 2007. In 2006, a large majority of the wellhead natural gas volumes from the United Kingdom were sold on the spot market. The remaining volumes were sold by means of forward contracts. The marketing strategy for the wellhead natural gas volumes in the United Kingdom is expected to remain the same in 2007.

Substantially all of EOG's wellhead crude oil and condensate is sold under various terms and arrangements at market-responsive prices.

During 2006, sales to a major integrated oil and gas company with investment grade credit ratings accounted for 11% of EOG's oil and gas revenues. No other individual purchaser accounted for 10% or more of EOG's oil and gas revenues for the same period. EOG does not believe that the loss of any single purchaser will have a material adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of and average prices for natural gas per thousand cubic feet (Mcf), crude oil and condensate per barrel (Bbl) and natural gas liquids per Bbl. The table also presents natural gas equivalent volumes on a thousand cubic feet equivalent basis (Mcfe - natural gas equivalents are determined using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil, condensate or natural gas liquids) delivered during each of the three years in the period ended December 31, 2006.

	2006	2005	2004
Natural Gas Volumes (MMcfd) (1)			
United States	817	718	631
Canada	226	228	212
Trinidad	264	231	186
United Kingdom	30	39	7
Total	1,337	1,216	1,036
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	20.7	21.5	21.1
Canada	2.5	2.4	2.7
Trinidad	4.8	4.5	3.6
United Kingdom	0.1	0.2	-
Total	28.1	28.6	27.4
Natural Gas Liquids Volumes (MBbld) (1)			
United States	8.5	6.6	4.8
Canada	0.8	0.9	0.8
Total	9.3	7.5	5.6
Natural Gas Equivalent Volumes (MMcfed) (2)			
United States	992	886	786
Canada	246	248	233
Trinidad	292	259	207
United Kingdom	31	40	7

Total	1,561	1,433	1,233
Average Natural Gas Prices ($/Mcf) (3)			
United States	$ 6.56	$ 7.86	$ 5.72
Canada	6.41	7.14	5.22
Trinidad	2.44	2.20 (4)	1.51
United Kingdom	7.69	6.99	5.14
Composite	5.74	6.62	4.86
Average Crude Oil and Condensate Prices ($/Bbl) (3)			
United States	$62.68	$54.57	$40.73
Canada	57.32	50.49	37.68
Trinidad	63.87	57.36	39.12
United Kingdom	57.74	49.62	-
Composite	62.38	54.63	40.22
Average Natural Gas Liquids Prices ($/Bbl) (3)			
United States	$39.95	$35.59	$27.79
Canada	43.69	35.59	23.23
Composite	40.25	35.59	27.13

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Million cubic feet equivalent per day, includes natural gas, crude oil, condensate and natural gas liquids.
(3) Dollars per thousand cubic feet or per barrel, as applicable.
(4) Includes $0.23 per Mcf as a result of a revenue adjustment related to an amended Trinidad take-or-pay contract.

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Competition

EOG competes for reserve acquisitions and exploration/exploitation leases, licenses and concessions, frequently against companies with substantially larger financial and other resources. To the extent EOG's exploration budget is lower than that of certain of its competitors, EOG may be disadvantaged in effectively competing for certain reserves, leases, licenses and concessions. Competitive factors include price, contract terms and quality of service, including pipeline connection times and distribution efficiencies. In addition, EOG faces competition from other worldwide energy supplies, such as liquefied natural gas imported into the United States from other countries. Please refer to

ITEM 1A. Risk Factors beginning on page 13.

Regulation

United States Regulation of Natural Gas and Crude Oil Production.

Natural gas and crude oil production operations are subject to various types of regulation, including regulation in the United States by state and federal agencies.

United States legislation affecting the oil and gas industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations which, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas and liquid hydrocarbon resources through proration and restrictions on flaring, require drilling bonds and regulate environmental and safety matters.

A substantial portion of EOG's oil and gas leases in Utah, Wyoming and the Gulf of Mexico, as well as some in other areas, are granted by the federal government and administered by the Bureau of Land Management (BLM) and the Minerals Management Service (MMS), both federal agencies. Operations conducted by EOG on federal oil and gas leases must comply with numerous statutory and regulatory restrictions. Certain operations must be conducted pursuant to appropriate permits issued by the BLM and the MMS.

BLM and MMS leases contain relatively standardized terms requiring compliance with detailed regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act (which are subject to change by the MMS). Such offshore operations are subject to numerous regulatory requirements, including the need for prior MMS approval for exploration, development, and production plans, stringent engineering and construction specifications applicable to offshore production facilities, regulations restricting the flaring or venting of production, and regulations governing the plugging and abandonment of offshore wells and the removal of all production facilities. Under certain circumstances, the MMS may require operations on federal leases to be suspended or terminated. Any such suspension or termination could adversely affect EOG's interests.

Sales of crude oil, condensate and natural gas liquids by EOG are made at unregulated market prices.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978 (NGPA). These statutes are administered by the Federal Energy Regulatory Commission (FERC). Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales.

EOG owns, directly or indirectly, certain natural gas pipelines that it believes meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. EOG's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's natural gas gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement, and management of facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, such legislation might have on its operations, the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the state legislatures, the FERC, the state regulatory commissions and the federal and state courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less regulated approach currently being followed by the FERC will continue indefinitely.

Environmental Regulation - United States.

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

EOG is aware of the increasing focus of local, national and international regulatory bodies on gaseous emissions and climate change. EOG believes that its strategy, to reduce emissions throughout our operations, is in the best interest of the environment and a generally good business practice. EOG will continue to review the risks to the company, associated with all environmental matters, including global warming/climate change.

Canadian Regulation of Natural Gas and Crude Oil Production

. The crude oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. These regulatory authorities may impose regulations on or otherwise intervene in the oil and natural gas industry with respect to prices, taxes, transportation rates, the exportation of the commodity and, possibly, expropriation or cancellation of contract rights. Such regulations may be changed from time to time in response to complaints or economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for these commodities, increase EOG's costs and may have a material adverse impact on its operations.

It is not expected that any of these controls or regulations will affect EOG operations in a manner materially different than they would affect other oil and gas companies of similar size. EOG is unable to predict what additional legislation or amendments may be enacted.

In addition, each province has regulations that govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from private lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

Environmental Regulation - Canada.

All phases of the crude oil and natural gas industry in Canada are subject to environmental regulation pursuant to a variety of Canadian federal, provincial, and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. These laws and regulations also require that facility sites and other properties associated with EOG's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications. These laws and regulations are subject to frequent change and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. While compliance with such

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legislation can require significant expenditures, failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties, suspension or revocation of licenses and, in some instances, the issuance of injunctions to limit or cease operations.

Spills and releases from EOG's properties may have resulted or result in soil and groundwater contamination in certain locations. Such contamination is not unusual within the crude oil and natural gas industry. Any contamination found on, under or originating from the properties may be subject to remediation requirements under Canadian laws. EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, EOG could be held responsible for oil and gas properties in which EOG owns an interest but is not the operator.

In December 2002, the Canadian federal government ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change, which requires Canada to reduce its greenhouse gas emissions to 6% below 1990 levels over the 2008-2012 periods. The *Climate Change Plan for Canada*, which was released in November 2002, outlined, in very general terms, the approach the Canadian government intended to take to implement its emissions reduction commitment. The Canadian government issued a further climate change plan, *Moving Forward on Climate Change: A Plan for Honouring our Kyoto Commitment*, in April of 2005. With the change in government at the federal level since the issuance of the 2005 plan, it is unclear how Canada intends to meet its Kyoto Protocol obligations. The final rules, once known, could affect operations and profitability.

Other International Regulation.

EOG's exploration and production operations outside the United States and Canada are subject to various types of regulations imposed by the respective governments of the countries in which EOG's operations are conducted, and may affect EOG's operations and costs within that country. EOG currently has operations in Trinidad and the United Kingdom.

Other Matters

Energy Prices.

Since EOG is primarily a natural gas producer, it is more significantly impacted by changes in prices of natural gas than changes in prices of crude oil, condensate or natural gas liquids. Average United States and Canada wellhead natural gas prices have fluctuated, at times rather dramatically, during the last three years. These fluctuations resulted in a 12% increase in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2003 to 2004, an increase of 37% from 2004 to 2005, and a decrease of 15% from 2005 to 2006. In 2006, a large majority of the wellhead natural gas volumes from Trinidad were sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes were sold under a contract at prices partially dependent on the United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad will remain the same in 2007. In 2006, a large majority of the wellhead natural gas volumes from the United Kingdom were sold on the spot market. The remaining volumes were sold by means of forward contracts. The marketing strategy for the wellhead natural gas volumes in the United Kingdom is expected to remain the same in 2007. Crude oil and condensate prices also have fluctuated during the last three years. Due to the many uncertainties associated with the world political environment, the availabilities of other world wide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in natural gas, crude oil and condensate, ammonia and methanol prices in the future.

Assuming a totally unhedged position for 2007, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2007 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $27 million for net income and operating cash flow. EOG's price sensitivity in 2007 for each $1.00 per barrel change in wellhead crude oil price is approximately $6 million for net income and operating cash flow. Summarized below and in Note 11 to Consolidated Financial Statements is information regarding EOG's current 2007 natural gas and crude oil hedge position.

Risk Management.

EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collar and price swap contracts, as the means tomanage this price risk. EOG accounts for financial commodity derivative contracts using the mark-to-market accounting method. In addition to financial transactions, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. Under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149, these physical commodity contracts qualify for the normal purchases and normal sales exception and therefore, are not subject to hedge accounting or mark-to-market accounting. The

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financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices. For a summary of EOG's financial commodity derivative contracts, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Derivative Transactions.

All of EOG's natural gas and crude oil activities are subject to the risks normally incident to the exploration for and development and production of natural gas and crude oil, including blowouts, cratering and fires, each of which could result in damage to life and/or property. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions. EOG's activities are also subject to governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. In accordance with customary industry practices, insurance is maintained by EOG against some, but not all, of the risks. Losses and liabilities arising from such events could reduce revenues and increase costs to EOG to the extent not covered by insurance.

EOG's operations outside of the United States are subject to certain risks, including expropriation of assets, risks of increases in taxes and government royalties, renegotiation of contracts with foreign governments, political instability, payment delays, limits on allowable levels of production and currency exchange and repatriation losses, as well as changes in laws, regulations and policies governing operations of foreign companies. Please refer to Item 1A. Risk Factors beginning on page 13 for further discussion of the risks to which EOG is subject.

Texas Severance Tax Rate Reduction.

Natural gas production from qualifying Texas wells spudded or completed after August 31, 1996, is entitled to a reduced severance tax rate for the first 120 consecutive months of production. However, the cumulative value of the tax reduction cannot exceed 50 percent of the drilling and completion costs incurred on a well-by-well basis. For the impact on EOG, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Taxes Other Than Income Taxes.

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

The Rights will not be exercisable until ten days after a public announcement that a person or group has become an acquiring person (Acquiring Person) by obtaining beneficial ownership of 10% or more of EOG's common stock, or if earlier, ten business days (or a later date determined by EOG's Board before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if consummated, would result in that person or group becoming an Acquiring Person. On February 24, 2005, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more, but less than 20%, of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the following requirements: (i) the institutional investor is described in Rule 13d-1(b)(1) promulgated under the Securities Exchange Act of 1934 and is eligible to report (and, if such institutional investor is the beneficial owner of greater than 5% of EOG's common stock, does in fact report) beneficial ownership of common stock on Schedule 13G; (ii) the institutional investor is not required to file a Schedule 13D (or any successor or comparable report) with respect to its beneficial ownership of EOG's common stock; (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates other than those which, under published interpretations of the United States Securities and Exchange Commission or its staff, are eligible to file separate reports on Schedule 13G with respect to their beneficial ownership of EOG's common stock); and (iv) the institutional investor does not beneficially own 20% or more of EOG's common stock (including in such calculation the holdings of all of the

institutional investor's affiliates and associates). On June 15, 2005, the Rights Agreement was amended again to revise the exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 30% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the other requirements of the definition of qualified institutional investor described in the amendment.

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

EOG's Board may redeem the Rights for $0.005 per Right at any time before any person or group becomes an Acquiring Person. If the Board redeems any Rights, it must redeem all of the Rights. Once the Rights are redeemed, the only right of the holders of Rights will be to receive the redemption price of $0.005 per Right. The redemption price has been adjusted for the two-for-one stock split effective March 1, 2005 and will be adjusted for any future stock split or stock dividends of EOG's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of EOG's outstanding common stock, the Board may exchange the

Rights for common stock or equivalent security at an exchange ratio of one share of common stock or an equivalent security for each such Right, other than Rights held by the Acquiring Person.

Preferred Stock.

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

On July 19, 2000, EOG's Board authorized 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (Series B). Dividends are payable on the shares only if declared by EOG's Board and will be cumulative. If declared, dividends will be payable at a rate of $71.95 per share, per year on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. EOG may redeem all or part of the Series B at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The Series B is not convertible into, or exchangeable for, common stock of EOG. On October 11, 2006, EOG commenced a cash tender offer to purchase any and all of the 100,000 outstanding shares of the Series B at a price of $1,074.01 per share plus accrued and unpaid dividends up to the date of purchase. The tender offer expired on November 8, 2006, and on November 10, 2006, EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including redemption premium, fees and dividends, of $51 million. EOG has included as a component of preferred dividends the $4 million of premium and fees associated with the redemption of the Series B shares. A total of 53,260 shares of the Series B remain outstanding at December 31, 2006.

Current Executive Officers of the Registrant

The current executive officers of EOG and their names and ages are as follows:

Name	Age	Position
Mark G. Papa	60	Chairman of the Board and Chief Executive Officer; Director
Loren M. Leiker	53	Senior Executive Vice President, Exploration
Edmund P. Segner, III	53	Senior Executive Vice President and Chief of Staff; Director
Gary L. Thomas	57	Senior Executive Vice President, Operations
Robert K. Garrison	54	Executive Vice President, Exploration
Barry Hunsaker, Jr.	57	Senior Vice President and General Counsel
Timothy K. Driggers	45	Vice President and Chief Accounting Officer

Mark G. Papa was elected Chairman of the Board and Chief Executive Officer of EOG in August 1999, President and Chief Executive Officer and Director in September 1998, President and Chief Operating Officer in September 1997, President in December 1996 and was President-North America Operations from February 1994 to September 1998. Mr. Papa joined Belco Petroleum Corporation, a predecessor of EOG, in 1981. Mr. Papa is EOG's principal executive officer.

Loren M. Leiker was elected Senior Executive Vice President, Exploration on February 26, 2007. He was elected Executive Vice President, Exploration in May 1998 and was subsequently named Executive Vice President, Exploration and Development. He was previously Senior Vice President, Exploration. Mr. Leiker joined EOG in April 1989 as International Exploration Manager.

Edmund P. Segner, III was elected Senior Executive Vice President and Chief of Staff on February 26, 2007. He was elected President and Chief of Staff and Director of EOG in August 1999. He was elected Vice Chairman and Chief of Staff of EOG in September 1997. He was a director of EOG from January 1997 to October 1997. Mr. Segner is EOG's principal financial officer.

Gary L. Thomas was elected Senior Executive Vice President, Operations on February 26, 2007. He was elected Executive Vice President, North America Operations in May 1998 and was subsequently named Executive Vice President, Operations. He was previously Senior Vice President and General Manager in Midland. Mr. Thomas joined a predecessor of EOG in July 1978.

Robert K. Garrison was elected Executive Vice President, Exploration on February 26, 2007. He previously was elected Senior Vice President and General Manager in Corpus Christi in August 2004. Prior to that he was Vice President and General Manager in Corpus Christi.

Barry Hunsaker, Jr. has been Senior Vice President and General Counsel since he joined EOG in May 1996.

Timothy K. Driggers was elected Vice President and Controller of EOG in October 1999 and was subsequently named Vice President and Chief Accounting Officer in August 2003. He was previously Vice President, Accounting and Land Administration. Mr. Driggers is EOG's principal accounting officer.

There are no family relationships among the officers listed, and there are no arrangements or understandings pursuant to which any of them were elected as officers. Officers are appointed or elected annually by the Board of Directors at its meeting immediately prior to the Annual Meeting of Shareholders, each to hold office until the corresponding meeting of the Board in the next year or until a successor shall have been duly elected or appointed and shall have qualified.

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ITEM 1A. *Risk Factors*

Our business faces many risks. The risks described below may not be the only risks we face. Additional risks that we do not yet know of, or that we currently think are immaterial, may also impair our business operations or financial results. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline. The following risk factors should be read in conjunction with the other information contained in this report, including the consolidated financial statements and the related notes.

A substantial or extended decline in natural gas or crude oil prices would have a material adverse effect on us.

Prices for natural gas and crude oil fluctuate widely. Since we are primarily a natural gas company, we are more significantly affected by changes in natural gas prices than changes in the prices for crude oil, condensate or natural gas liquids. Among the factors that can cause these price fluctuations are:

- the level of consumer demand;
- weather conditions;
- domestic drilling activity;
- the price and availability of alternative fuels, including liquefied natural gas;

- the proximity to, and capacity of, transportation facilities;
- worldwide economic and political conditions;
- the effect of worldwide energy conservation measures; and
- the nature and extent of governmental regulation and taxation.

Our cash flow and earnings depend to a great extent on the prevailing prices for natural gas and crude oil. Prolonged or substantial declines in these commodity prices may adversely affect our liquidity, the amount of cash flow we have available for capital expenditures and our ability to maintain our credit quality and access to the credit and capital markets.

Our ability to sell our crude oil and natural gas production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities or our failure to obtain these services on acceptable terms could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future.

Weather and climate may have a significant impact on our revenues and productivity.

Demand for natural gas and oil is, to a significant degree, dependent on weather and climate, which impacts the price we receive for the commodities we produce. In addition, our exploration and development activities and equipment can be adversely affected by severe weather, such as hurricanes in the Gulf of Mexico, which may cause a loss of production from temporary cessation of activity or lost or damaged equipment.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our underlying assumptions could cause the quantities of our reserves to be misstated.

Estimating quantities of proved crude oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions or changes of conditions could cause the quantities of our reserves to be overstated or understated.

To prepare estimates of economically recoverable crude oil and natural gas reserves and future net cash flows, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce our estimated quantities and present value of reserves.

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If we fail to acquire or find sufficient additional reserves, our reserves and production will decline from their current levels.

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, acquire additional properties containing proved reserves, or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future crude oil and natural gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of factors that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements, which may increase our costs or restrict our activities;
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment;
- lack of infrastructure; and
- lack of trained drilling personnel.

We incur certain costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future.

Our exploration, production and marketing operations are regulated extensively at the federal, state and local levels, as well as by other governments/authorities in countries in which we do business. We have and will continue to incur costs in our efforts to comply with the requirements of environmental and other regulations. Further, the crude oil and natural gas industry regulatory environment could change in ways that might substantially increase these costs.

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, local and foreign regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could hurt our business.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities.

The exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can damage or destroy wells or production facilities, injure or kill people, and damage property and the environment. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts that we believe to be prudent. Losses and liabilities arising from such events could reduce our revenues and increase our costs to the extent not covered by insurance.

The occurrence of any of these events and any costs incurred as a result of such events and the liabilities related thereto, would reduce the funds available for exploration, drilling and production and could have a material adverse effect on our financial position or results of operations.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

From time to time, we use derivative instruments (primarily collars and price swaps) to hedge the impact of market fluctuations of natural gas and crude oil prices on net income and cash flow. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges. In addition, we are subject to risks associated with differences in prices at different locations, particularly where

transportation constraints restrict our ability to deliver oil and gas volumes to the delivery point to which the hedging transaction is indexed.

If we acquire oil and gas properties, our failure to fully identify potential problems, to properly estimate reserves or production rates or costs, or to effectively integrate the acquired operations could seriously harm us.

From time to time, we seek to acquire oil and gas properties. Although we perform reviews of acquired properties that we believe are consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor do they permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties. Actual results may vary substantially from those assumed in the estimates.

In addition, acquisitions may have adverse effects on our operating results, particularly during the periods in which the operations of acquired properties are being integrated into our ongoing operations.

Terrorist activities and military and other actions could adversely affect our business.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as the military or other actions taken in response to these acts, cause instability in the global financial and energy markets. The United States government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These actions could adversely affect us in unpredictable ways, including the disruption of fuel supplies and markets, increased volatility in crude oil and natural gas prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terror.

Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with major integrated and other independent oil and gas companies for acquisition of oil and gas leases, properties and reserves, equipment and labor required to explore, develop and operate those properties and the marketing of crude oil and natural gas production. Higher recent crude oil and natural gas prices have increased the costs of properties available for acquisition and there are a greater number of companies with the financial resources to pursue acquisition opportunities.

Many of our competitors have financial and other resources substantially larger than those we possess and have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new or expanded entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights.

In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas production, such as changing worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers and other specialists.

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

We make, and will continue to make, substantial capital expenditures for the acquisition, development, production, exploration and abandonment of our oil and gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, commercial paper and to a lesser extent and if necessary, bank borrowings, public and private equity and debt offerings. Lower crude oil and natural gas prices, however, would

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reduce our cash flow. Further, if the condition of the capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable. In addition, a substantial rise in interest rates would decrease our net cash flows available for reinvestment.

ITEM 1B. *Unresolved Staff Comments*

None.

ITEM 2. *Properties*

Oil and Gas Exploration and Production Properties and Reserves

Reserve Information.

For estimates of EOG's net proved and proved developed reserves of natural gas and liquids, including crude oil, condensate and natural gas liquids, see Supplemental Information to Consolidated Financial Statements.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in Supplemental Information to Consolidated Financial Statements represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, crude oil, condensate and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

In general, production from EOG's oil and gas properties declines as reserves are depleted. Except to the extent EOG acquires additional properties containing proved reserves or conducts successful exploration, exploitation and development activities, the proved reserves of EOG will decline as reserves are produced. Volumes generated from future activities of EOG are therefore highly dependent upon the level of success in finding or acquiring additional reserves and the costs incurred in so doing. EOG's estimates of reserves filed with other federal agencies agree with the information set forth in Supplemental Information to Consolidated Financial Statements.

Acreage.

The following table summarizes EOG's developed and undeveloped acreage at December 31, 2006. Excluded is acreage in which EOG's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States						
Texas	641,774	401,143	2,053,312	1,247,510	2,695,086	1,648,653
Wyoming	203,441	142,191	373,914	234,665	577,355	376,856
Oklahoma	257,904	149,570	294,512	219,918	552,416	369,488
New Mexico	108,176	72,413	241,028	147,980	349,204	220,393
Offshore Gulf of Mexico	192,519	71,556	124,375	82,277	316,894	153,833
Utah	88,118	59,439	227,493	148,876	315,611	208,315
Montana	153,292	18,103	123,578	69,997	276,870	88,100
Pennsylvania	82,831	71,400	164,216	144,938	247,047	216,338
North Dakota	3,973	1,240	214,771	142,972	218,744	144,212
Nevada	-	-	207,637	207,070	207,637	207,070
Louisiana	17,343	10,206	118,146	76,674	135,489	86,880
Ohio	60,097	56,684	69,350	63,372	129,447	120,056
West Virginia	38,263	30,290	82,914	55,278	121,177	85,568
Colorado	22,944	1,309	96,943	70,482	119,887	71,791
Mississippi	29,207	18,974	72,781	20,104	101,988	39,078
New York	2,038	1,088	88,199	78,512	90,237	79,600
California	8,907	5,872	69,804	60,235	78,711	66,107
Alabama	-	-	75,267	55,225	75,267	55,225
Virginia	998	963	38,160	37,841	39,158	38,804
Kansas	12,692	11,302	19,358	16,455	32,050	27,757
Michigan	-	-	3,588	3,588	3,588	3,588
Arkansas	-	-	834	132	834	132
Total United States	1,924,517	1,123,743	4,760,180	3,184,101	6,684,697	4,307,844
Canada						
Alberta	1,396,660	1,135,065	766,882	701,717	2,163,542	1,836,782
Northwest Territories	978	258	887,198	233,979	888,176	234,237
Nova Scotia	-	-	749,213	374,606	749,213	374,606
Saskatchewan	378,405	349,207	89,776	85,903	468,181	435,110
British Columbia	1,326	834	140,506	127,273	141,832	128,107

Manitoba	15,738	15,135	44,462	44,342	60,200	59,477
New Brunswick	219	33	-	-	219	33
Total Canada	1,793,326	1,500,532	2,678,037	1,567,820	4,471,363	3,068,352
Trinidad	49,642	44,160	251,714	208,723	301,356	252,883
United Kingdom	10,230	2,946	589,678	352,434	599,908	355,380
Total	3,777,715	2,671,381	8,279,609	5,313,078	12,057,324	7,984,459

Producing Well Summary.

The following table reflects EOG's ownership in producing natural gas and crude oil wells located in the United States, Canada, Trinidad and the United Kingdom at December 31, 2006. Gross natural gas and crude oil wells include 2,365 with multiple completions.

	Productive Wells	
	Gross	Net
Natural Gas	20,512	17,252
Crude Oil	1,837	1,263
Total	22,349	18,515

Drilling and Acquisition Activities.

During the years ended December 31, 2006, 2005 and 2004, EOG expended $2,996 million, $1,878 million and $1,510 million, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of $22 million, $20 million and $16 million, respectively. EOG drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
United States and Canada						
Gas	2,240	1,921.5	1,523	1,241.3	1,839	1,623.3
Oil	60	49.9	79	68.6	92	79.3
Dry	66	57.2	80	70.0	104	86.9
	2,366	2,028.6	1,682	1,379.9	2,035	1,789.5
Total Outside United States and Canada						

Gas	1	0.3	2	0.6	5	4.1
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	1	0.3	2	0.6	5	4.1
Total Development	2,367	2,028.9	1,684	1,380.5	2,040	1,793.6
Exploratory Wells Completed						
United States and Canada						
Gas	53	44.8	61	47.0	49	44.2
Oil	2	1.8	3	2.6	5	3.0
Dry	21	17.0	23	17.5	41	29.2
Total	76	63.6	87	67.1	95	76.4
Outside United States and Canada						
Gas	2	1.8	-	-	1	1.0
Oil	-	-	-	-	-	-
Dry	-	-	3	0.7	3	1.9
Total	2	1.8	3	0.7	4	2.9
Total Exploratory	78	65.4	90	67.8	99	79.3
Total	2,445	2,094.3	1,774	1,448.3	2,139	1,872.9
Wells in Progress at end of period	221	180.9	160	123.9	63	49.4
Total	2,666	2,275.2	1,934	1,572.2	2,202	1,922.3
Total Wells Acquired[1]						
Gas	114	106.4	37	20.4	249	151.7
Oil	1	1.0	-	-	8	7.3
Total	115	107.4	37	20.4	257	159.0

(1) Includes the acquisition of additional interests in certain wells in which EOG previously owned an interest.

All of EOG's drilling activities are conducted on a contract basis with independent drilling contractors. EOG owns no drilling equipment.

ITEM 3. *Legal Proceedings*

The information required by this Item is included in this report as set forth in the Contingencies section in Note 7 of Notes to Consolidated Financial Statements on page F-23.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2006.

PART II

ITEM 5. *Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity* Securities

The following table sets forth, for the periods indicated, the high and low price per share for the common stock of EOG, as reported on the New York Stock Exchange Composite Tape, and the amount of common stock dividend declared per share.

	Price Range		
	High	Low	Dividend Declared
2006			
First Quarter	$86.91	$64.12	$ 0.06
Second Quarter	79.24	56.31	0.06
Third Quarter	75.56	58.45	0.06
Fourth Quarter	72.27	59.88	0.06
2005			
First Quarter	$48.84	$32.05	$ 0.04
Second Quarter	57.94	42.40	0.04
Third Quarter	77.00	57.18	0.04
Fourth Quarter	82.00	59.96	0.04

On February 1, 2006, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the previous $0.04 per share to $0.06 per share.

On January 31, 2007, the Board increased the quarterly cash dividend on the common stock from the previous $0.06 per share to $0.09 per share.

As of February 16, 2007, there were approximately 260 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 123,000 beneficial owners of EOG's common stock, including shares held in street name.

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

The following table sets forth, for the periods indicated, EOG's repurchase activity:

Period	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs[2]
October 1, 2006 - October 31, 2006	-		-	6,386,200
November 1, 2006 - November 30, 2006	-		-	6,386,200
December 1, 2006 - December 31, 2006	3,759	$69.19	-	6,386,200
Total	3,759	$69.19		

(1) The quarterly total number of shares of 3,759 consists solely of 1,430 shares (23,232 shares for the full year 2006) that were returned to EOG in payment of the exercise price of employee stock options and 2,329 shares (241,931 shares for the full year 2006) that were withheld by or returned to EOG to satisfy tax withholding obligations that arose upon the exercise of employee stock options or the vesting of restricted stock or units.

(2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2006, EOG did not repurchase any shares under the Board authorized repurchase program.

ITEM 6. *Selected Financial Data*

(In Thousands, Except Per Share Data)

Year Ended December 31	2006	2005	2004	2003	2002
Statement of Income Data:					

Net Operating Revenues	$	3,904,415	$	3,620,213	$	2,271,225	$	1,744,675	$	1,094,682
Operating Income		1,895,426		1,991,815		979,195		697,314		180,977
Net Income Before Cumulative Effect of Change in Accounting Principle		1,299,885		1,259,576		624,855		437,276		87,173
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)		-		-		-		(7,131)		-
Net Income		1,299,885		1,259,576		624,855		430,145		87,173
Preferred Stock Dividends		10,995		7,432		10,892		11,032		11,032
Net Income Available to Common	$	1,288,890	$	1,252,144	$	613,693	$	419,113	$	76,141
Net Income Per Share Available to Common(2)										
Basic										
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$	5.33	$	5.24	$	2.63	$	1.86	$	0.33
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)		-		-		-		(0.03)		-
Net Income Per Share Available to Common	$	5.33	$	5.24	$	2.63	$	1.83	$	0.33
Diluted										
Net Income Available to Common Before Cumulative Effect of Change in Accounting Principle	$	5.24	$	5.13	$	2.58	$	1.83	$	0.32
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)		-		-		-		(0.03)		-
Net Income Per Share Available to Common	$	5.24	$	5.13	$	2.58	$	1.80	$	0.32
Dividends Per Common Share(2)	$	0.240	$	0.160	$	0.120	$	0.095	$	0.080
Average Number of Common Shares(2)										
Basic		241,782		238,797		233,751		229,194		230,669
Diluted		246,100		243,975		238,376		233,037		234,491

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

different from the actual amount reported.

(2) Years 2002 through 2004 restated for two-for-one stock split effective March 1, 2005.

At December 31	2006	2005	2004	2003	2002
Balance Sheet Data:					
Net Oil and Gas Properties	$ 7,944,047	$ 6,087,179	$ 5,101,603	$ 4,248,917	$ 3,321,548
Total Assets	9,402,160	7,753,320	5,798,923	4,749,015	3,813,568
Current and Long-Term Debt	733,442	985,067	1,077,622	1,108,872	1,145,132
Shareholders' Equity	5,599,671	4,316,292	2,945,424	2,223,381	1,672,395

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ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

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

Net income available to common for 2006 of $1,289 million was up 3% compared to 2005 net income available to common of $1,252 million. At December 31, 2006, EOG's total reserves were 6.8 trillion cubic feet equivalent, an increase of 607 billion cubic feet equivalent (Bcfe) from December 31, 2005.

Operations

Several important developments have occurred since January 1, 2006.

United States and Canada. EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG plans to continue to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's crude oil and natural gas production. Production in the United States and Canada accounted for approximately 79% of total company production in both 2006 and 2005. Based on current trends, EOG expects its 2007 production profile to be similar. EOG's major producing areas are in Louisiana, New Mexico, Oklahoma, Texas, Utah, Wyoming and western Canada.

International.

Although EOG continues to focus on United States and Canada natural gas, EOG sees an increasing linkage between United States and Canada natural gas demand and Trinidad natural gas supply. For example, liquefied natural gas (LNG) imports from existing and planned facilities in Trinidad are contenders to meet increasing United States natural gas demand. In addition, ammonia, methanol and chemical production has been relocating from the United States and Canada to Trinidad, driven by attractive natural gas feedstock prices in the island nation. EOG believes that its existing position with the supply contracts to two ammonia plants, a methanol plant and the Atlantic LNG Train 4 (ALNG) plant will continue to give its portfolio an even broader exposure to United States and Canada natural gas fundamentals.

Beginning December 2005, ALNG began taking start-up gas and remained in the start-up phase through December 2006. In the first quarter of 2006, a subsidiary of EOG, EOG Resources Trinidad Block 4(a) Unlimited, drilled two successful wells on Block 4(a). The subsidiary obtained approval to develop Block 4(a) under a production sharing contract with the Government of Trinidad and Tobago signed in July 2005.

A subsidiary of EOG, EOG Resources Trinidad Limited, and the other participants in the South East Coast Consortium (SECC) Block signed a farm-out agreement covering the SECC Deep Ibis prospect with BP Trinidad and Tobago LLC (BP) during 2004. The SECC Deep Ibis well spud in April 2006, was drilled to a depth of approximately 19,000 feet and was abandoned and classified as a dry hole in the third quarter of 2006. BP paid the entire cost for drilling the SECC Deep Ibis exploratory well.

During 2006, notwithstanding difficulties in accessing rig slots in the Southern Gas Basin of the United Kingdom North Sea, Arthur 3 was drilled and completed and began producing in early third quarter. In addition to EOG's ongoing production from Valkyrie and Arthur Fields, EOG participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. The Columbus well was a farm-in opportunity, and its future appraisal and development is currently being evaluated.

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Capital Structure

One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. At December 31, 2006, EOG's debt-to-total capitalization ratio was 12%, down from 19% at year-end 2005. By primarily utilizing cash on hand and cash provided from its operating activities, EOG funded its $2,974 million exploration and development expenditures, paid down $317 million of debt, paid dividends to common shareholders of $60 million and redeemed $47 million of preferred stock. As management continues to assess price forecast and demand trends for 2007, EOG believes that operations and capital expenditure activity can be largely funded by cash from operations.

For 2007, EOG's estimated exploration and development expenditure budget is approximately $3.4 billion, excluding acquisitions. United States and Canada natural gas drilling activity continues to be a key component of these expenditures. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

On September 15, 2006, EOG filed an automatically effective shelf registration statement on Form S-3 (New Registration Statement) for the offer and sale from time to time of up to $688,237,500 of EOG's debt securities, preferred stock and common stock. The New Registration Statement was filed to replace EOG's existing shelf registration statement declared effective by the Securities and Exchange Commission (SEC) in October 2000, under which EOG had sold no securities. As of February 26, 2007, the entire amount registered remains available under the New Registration Statement.

On October 11, 2006, EOG commenced a cash tender offer to purchase any and all of the 100,000 outstanding shares of the 7.195% Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (Series B), at a price of $1,074.01 per share plus accrued and unpaid dividends up to the date of purchase. The tender offer expired on November 8, 2006, and on November 10, 2006, EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including redemption premium, fees and dividends, of $51 million. EOG has included as a component of preferred dividends the $4 million of premium and fees associated with the redemption of the Series B shares. A total of 53,260 shares of the Series B remain outstanding at December 31, 2006.

Stock-Based Compensation.

EOG adopted Statement of Financial Accounting Standards (SFAS) No. 123(R), "Share-Based Payment" effective January 1, 2006 using the modified prospective application method and accordingly has not restated any of its prior year results. See Note 6 to Consolidated Financial Statements. Prior to the adoption of SFAS No. 123(R), EOG recognized compensation expense for its stock-based compensation plans under the provisions of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." Stock-based compensation expense prior to January 1, 2006 consisted of amounts recognized in connection with grants of restricted stock and units. The adoption of SFAS No. 123(R) resulted in EOG recognizing compensation expense on grants made under its employee stock option plans and its employee stock purchase plan. For periods subsequent to January 1, 2006, stock-based compensation expense is included in the Consolidated Statements of Income based upon job functions of employees receiving the grants. For the years ended December 31, 2006, 2005 and 2004, EOG compensation expense related to its stock-based compensation plans was as follows (in millions):

	2006	2005	2004
Lease and Well	$ 10	$ -	$ -
Exploration Costs	11	-	-
General and Administrative	29	12	10
Total	$ 50	$ 12	$ 10

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2006 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2006, net operating revenues increased $284 million, or 8%, to $3,904 million from $3,620 million in 2005. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids, decreased $42 million, or 1%, to $3,565 million from $3,607 million in 2005. Wellhead volume and price statistics for the years ended December 31, were as follows:

	2006	2005	2004
Natural Gas Volumes (MMcfd) (1)			
United States	817	718	631
Canada	226	228	212
Trinidad	264	231	186
United Kingdom	30	39	7
Total	1,337	1,216	1,036
Average Natural Gas Prices ($/Mcf) (2)			
United States	$ 6.56	$ 7.86	$ 5.72
Canada	6.41	7.14	5.22
Trinidad	2.44	2.20 (4)	1.51
United Kingdom	7.69	6.99	5.14
Composite	5.74	6.62	4.86
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	20.7	21.5	21.1
Canada	2.5	2.4	2.7
Trinidad	4.8	4.5	3.6

United Kingdom	0.1	0.2	-
Total	28.1	28.6	27.4
Average Crude Oil and Condensate Prices ($/Bbl) (2)			
United States	$ 62.68	$ 54.57	$ 40.73
Canada	57.32	50.49	37.68
Trinidad	63.87	57.36	39.12
United Kingdom	57.74	49.62	-
Composite	62.38	54.63	40.22
Natural Gas Liquids Volumes (MBbld) (1)			
United States	8.5	6.6	4.8
Canada	0.8	0.9	0.8
Total	9.3	7.5	5.6
Average Natural Gas Liquids Prices ($/Bbl) (2)			
United States	$ 39.95	$ 35.59	$ 27.79
Canada	43.69	35.59	23.23
Composite	40.25	35.59	27.13
Natural Gas Equivalent Volumes (MMcfed) (3)			
United States	992	886	786
Canada	246	248	233
Trinidad	292	259	207
United Kingdom	31	40	7
Total	1,561	1,433	1,233
Total Bcfe (3) Deliveries	569.9	523.0	451.5

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Dollars per thousand cubic feet or per barrel, as applicable.
(3) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and
natural gas liquids. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil,
condensate or natural gas liquids.
(4) Includes $0.23 per Mcf as a result of a revenue adjustment related to an amended Trinidad take-or-pay contract.

J006 compared to 2005.

Wellhead natural gas revenues for 2006 decreased $136 million, or 5%, to $2,803 million from $2,939 million for 2005 due to a lower composite average wellhead natural gas price ($407 million) and a second quarter 2005 revenue adjustment related to an amended Trinidad take-or-pay contract ($19 million), partially offset by increased natural gas deliveries ($290 million). The composite average wellhead natural gas price decreased 13% to $5.74 per Mcf for 2006 from $6.62 per Mcf in 2005. The Trinidad take-or-pay contract adjustment increased the average Trinidad wellhead natural gas price by $0.23 per Mcf for 2005.

Natural gas deliveries increased 121 MMcfd, or 10%, to 1,337 MMcfd for 2006 from 1,216 MMcfd in 2005. The increase was due to higher production of 99 MMcfd in the United States and 33 MMcfd in Trinidad, partially offset by lower production of 9 MMcfd in the United Kingdom and 2 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (83 MMcfd), the Rocky Mountain area (24 MMcfd) and Kansas (7 MMcfd), partially offset by decreased production in the Gulf of Mexico (16 MMcfd). The decrease in Gulf of Mexico production was partially due to continued shut-in production caused by infrastructure damage from hurricanes Katrina and Rita. The increase in Trinidad was due to the commencement of two contracts late in the fourth quarter of 2005 (43 MMcfd) and increased contractual demand (34 MMcfd), partially offset by a decrease in volumes as a result of the December 2005 completion of a cost recovery arrangement (44 MMcfd). The decrease in production in the United Kingdom was a result of production declines in both the Arthur and Valkyrie fields.

Wellhead crude oil and condensate revenues increased $54 million, or 9%, to $625 million from $571 million as compared to 2005, due to an increase in the composite average wellhead crude oil and condensate price ($78 million), partially offset by a decrease in the wellhead crude oil and condensate deliveries ($24 million). The composite average wellhead crude oil and condensate price for 2006 was $62.38 per barrel compared to $54.63 per barrel for 2005.

Natural gas liquids revenues increased $40 million, or 41%, to $137 million from $97 million as compared to 2005, due to increases in deliveries ($24 million) and the composite average price ($16 million).

During 2006, EOG recognized gains on mark-to-market financial commodity derivative contracts of $334 million, which included realized gains of $215 million. During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million.

J005 compared to 2004.

Wellhead natural gas revenues for 2005 increased $1,097 million, or 60%, to $2,939 million from $1,842 million for 2004 due to a higher composite average wellhead natural gas price ($763 million), increased natural gas deliveries ($315 million) and a second quarter 2005 revenue adjustment related to an amended Trinidad take-or-pay contract ($19 million). The composite average wellhead natural gas price increased 36% to $6.62 per Mcf for 2005 from $4.86 per Mcf in 2004. Excluding the aforementioned adjustment, the composite average wellhead natural gas price increased 35% to $6.58 per Mcf for 2005. This adjustment increased the average Trinidad wellhead natural gas price by $0.23 per Mcf for 2005.

Natural gas deliveries increased 180 MMcfd, or 17%, to 1,216 MMcfd for 2005 from 1,036 MMcfd in 2004. The increase was due to higher production of 87 MMcfd in the United States, 45 MMcfd in Trinidad, 32 MMcfd in the United Kingdom and 16 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (63 MMcfd) and Louisiana (20 MMcfd). The increase in Trinidad was due to the increased contractual requirements and demand related to the ammonia and methanol plants. The increase in the United Kingdom was due to the commencement of production from the Arthur field in January 2005 (24 MMcfd) and the full year production from the Valkyrie field, which commenced production in August 2004 (8 MMcfd). The increase in Canada was attributable to the drilling program, primarily in the Wapiti, Drumheller and Connorsville areas.

Wellhead crude oil and condensate revenues increased $168 million, or 42%, to $571 million from $403 million as compared to 2004, due to increases in both the composite average wellhead crude oil and condensate price ($151 million) and the wellhead crude oil and condensate deliveries ($17 million). The composite average wellhead crude oil and condensate price for 2005 was $54.63 per barrel compared to $40.22 per barrel for 2004.

Natural gas liquids revenues increased $42 million, or 76%, to $97 million from $55 million as compared to 2004, due to increases in the composite average price ($23 million) and deliveries ($19 million).

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During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. During 2004, EOG recognized losses on mark-to-market financial commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million.

Operating and Other Expenses

2006 compared to 2005. During 2006, operating expenses of $2,009 million were $381 million higher than the $1,628 million incurred in 2005. The following table presents the costs per Mcfe for the years ended December 31:

	2006	2005
Lease and Well	$0.66	$0.54
Transportation Costs	0.19	0.17
Depreciation, Depletion and Amortization (DD&A)	1.44	1.25
General and Administrative (G&A)	0.29	0.24
Taxes Other Than Income	0.35	0.38
Net Interest Expense	0.08	0.12
Total Per-Unit Costs (1)	$3.01	$2.70

(1) Total per-unit costs do not include exploration costs, dry hole costs and impairments.

The change in per-unit rates of lease and well, transportation costs, DD&A, G&A, taxes other than income and net interest expense for 2006 as compared to 2005 were due primarily to the reasons set forth below.

Lease and well expenses include expenses for EOG operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain EOG's oil and natural gas wells, the cost of workovers, and lease and well administrative expenses. Operating and maintenance expenses include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep, and fuel and power. Workovers are costs of operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses of $373 million in 2006 were $86 million higher than 2005 due primarily to higher operating and maintenance expenses in the United States ($34 million) and Canada ($16 million); higher lease and well administrative expenses ($21 million), including stock-based compensation expense ($10 million); changes in the Canadian exchange rate ($6 million); and higher workover expenditures in the United States ($6 million).

Transportation costs represent costs incurred directly by EOG from third-party carriers associated with the delivery of hydrocarbon products from the lease to a down-stream point of sale. Transportation costs include the cost of compression (compressing natural gas to meet pipeline pressure requirements), dehydration (removing water from natural gas to meet pipeline requirements), gathering fees, fuel costs and transportation fees.

Transportation costs of $110 million in 2006 were $23 million higher than 2005 due primarily to increased production in the Fort Worth Basin Barnett Shale play.

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles; drilling or acquisition of new wells; disposition of existing wells; reserve revisions (upward or downward) primarily related to well performance; and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from year to year.

J5

DD&A expenses of $817 million in 2006 were $163 million higher than 2005 primarily due to higher unit rates described below and as a result of increased production in the United States ($56 million) and Trinidad ($3 million), partially offset by a decrease in production in the United Kingdom ($4 million). DD&A rates increased due primarily to a gradual proportional increase in production from higher cost properties in the United States ($78 million) and Canada ($11 million), and a downward reserve revision in the United Kingdom ($11 million). The Canadian exchange rate also contributed to the DD&A expense increase ($9 million).

G&A expenses of $165 million in 2006 were $39 million higher than 2005 due primarily to higher employee-related costs ($31 million) and higher insurance costs ($4 million). The increase in employee-related costs primarily reflects higher stock-based compensation expenses ($17 million).

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Taxes other than income of $201 million in 2006 were $2 million higher than 2005.

Severance taxes in the United States decreased primarily due to increased credits taken for Texas high cost gas severance tax rate reductions ($14 million). Severance/production taxes in Trinidad increased due primarily to increased wellhead revenues from crude oil and condensate ($12 million), partially offset by changes to the tax legislation governing the Supplemental Petroleum Tax ($7 million). Ad valorem/property taxes increased primarily due to higher property valuation in the United States ($7 million) and Canada ($2 million).

Net interest expense of $43 million in 2006 decreased $19 million compared to 2005 primarily due to lower average debt balance ($9 million), costs in 2005 associated with the early retirement of the 6.00% Notes due 2008 ($8 million), and higher capitalized interest ($5 million).

Exploration costs of $155 million in 2006 were $22 million higher than 2005 due primarily to higher employee-related costs, including stock-based compensation expenses.

Impairments include amortization of unproved leases, as well as impairments under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which requires an entity to compute impairments to the carrying value of long-lived assets based on future cash flow analysis. Impairments of $108 million in 2006 were $30 million higher than 2005 due primarily to increased SFAS No. 144 related impairments in the United States ($17 million) and Canada ($7 million) and higher amortization of unproved leases in Canada ($4 million) and the United States ($2 million). EOG recorded impairments of $55 million and $31 million for 2006 and 2005, respectively, under SFAS No. 144 for properties in the United States and Canada.

Other income, net was $60 million in 2006 compared to $36 million in 2005. The increase of $24 million was primarily due to higher interest income ($19 million), settlements received related to the Enron Corp. bankruptcy ($4 million) and increased net foreign currency transaction gains ($3 million), partially offset by lower gains on sales of properties ($5 million).

Income tax provision of $613 million in 2006 decreased $93 million compared to 2005 due primarily to a net decrease in foreign income taxes ($37 million), largely related to a Canadian federal tax rate reduction ($19 million) and an Alberta, Canada corporate tax rate reduction ($13 million), partially offset by a United Kingdom corporate tax rate increase ($7 million); reduced income taxes associated with the repatriation of foreign earnings in 2005 ($24 million); decreased pretax income ($18 million); and reduced state income taxes ($18 million), partially offset by a decrease in the Domestic Production Activities Deduction ($7 million). The effective tax rate for 2006 decreased to 32% from 36% in 2005.

2005 compared to 2004. During 2005, operating expenses of $1,628 million were $336 million higher than the $1,292 million incurred in 2004. The following table presents the costs per Mcfe for the years ended December 31:

	2005	**2004**
Lease and Well, including Transportation	$0.71	$0.60
DD&A	1.25	1.12
G&A	0.24	0.25
Taxes Other Than Income	0.38	0.30
Interest Expense, Net	0.12	0.14
Total Per-Unit Costs (1)	$2.70	$2.41

(1) Total per-unit costs do not include exploration costs, dry hole costs and impairments.

The per-unit rates of lease and well, including transportation, DD&A, taxes other than income and interest expense, net for 2005 compared to 2004 were due primarily to the reasons set forth below.

Lease and well expenses, including transportation, of $373 million were $102 million higher than 2004 due primarily to higher operating and maintenance expenses in the United States ($40 million); increased transportation related costs in the United States ($28 million) and the United Kingdom ($7 million); higher lease and well administrative expenses in the United States ($11 million); changes in the Canadian exchange rate ($6 million); and higher workover expenditures in the United States ($3 million) and Trinidad ($2 million).

DD&A expenses of $654 million in 2005 were $150 million higher than 2004 primarily as a result of increased production in the United States ($46 million), Canada ($6 million) and Trinidad ($5 million) and the commencement of production in the United Kingdom ($14 million). DD&A rates increased in the United States due to a gradual proportional increase in production from higher cost properties ($59 million) and in Canada predominantly from the development of acquired proved reserves ($9 million). The Canadian exchange rate also contributed to the DD&A expense increase ($8 million).

Taxes other than income of $199 million in 2005 were $65 million higher than 2004. Severance/production taxes increased due primarily to increased wellhead revenues in the United States ($41 million), Trinidad ($7 million) and Canada ($3 million), partially offset by the increase in credits taken for Texas high cost gas severance tax rate reductions ($10 million) and a production tax audit lawsuit in the first quarter of 2004 ($5 million). Other items contributing to the increase were an additional Trinidadian Supplemental Petroleum Tax expense as a result of 2005 tax legislation that increased the tax expense retroactively to January 2004 ($7 million) and 2004 production tax relief in Trinidad ($6 million). Ad valorem/property taxes increased primarily due to higher property valuation in the United States ($11 million).

Net interest expense in 2005 included costs associated with the early retirement of the 2008 Notes ($8 million) (see Note 2 to Consolidated Financial Statements). Excluding these early retirement costs, the 2005 net interest expense decreased $8 million compared to 2004 primarily due to higher capitalized interest ($5 million), an interest charge related to the results of a production tax audit lawsuit in the first quarter of 2004 ($2 million) and lower average debt balance in the United States ($1 million).

Exploration costs of $133 million in 2005 were $39 million higher than 2004 due primarily to increased geological and geophysical expenditures in the Fort Worth Basin Barnett Shale play.

Impairments of $78 million were $4 million lower than 2004 due primarily to lower amortization of unproved leases in the United States ($12 million) and lower impairments to the carrying value of certain long-lived assets in Canada ($8 million), partially offset by higher impairments to the carrying value of certain long-lived assets in the United States ($14 million) and higher amortization of unproved leases in Canada ($2 million). EOG recorded impairments of $31 million and $25 million for 2005 and 2004, respectively, under SFAS No. 144 for certain properties in the United States and Canada.

Other income, net of $36 million in 2005 increased $26 million compared to 2004 primarily as a result of higher gains on sales of properties ($7 million), interest income ($6 million) and equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants in 2005

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($5 million); decreased net foreign currency transaction losses ($4 million); and a gain on the sale of part of EOG's interest in the N2000 ammonia plant in the first quarter of 2005 ($2 million).

Income tax provision of $706 million increased $404 million as compared to 2004, due primarily to higher pretax income ($383 million) and income taxes associated with the repatriation of foreign earnings ($24 million). The effective tax rate for 2005 increased to 36% from 33% in 2004.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2006 included funds generated from operations, funds from new borrowings, proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan, and proceeds from the sale of oil and gas properties. The primary uses of cash were funds used in operations, exploration and development expenditures, repayment of debt, dividend payments to shareholders and redemption of preferred stock.

J006 compared to 2005.

Net cash provided by operating activities of $2,579 million in 2006 increased $209 million compared to 2005 primarily reflecting a favorable change in the net cash flows from settlement of financial commodity derivative contracts ($205 million), favorable changes in working capital and other liabilities ($162 million) and a decrease in cash paid for income taxes and interest expense ($54 million), partially offset by an increase in cash operating expenses ($173 million) and a decrease in wellhead revenues ($42 million).

Net cash used in investing activities of $2,710 million in 2006 increased by $1,032 million compared to 2005 due primarily to increased additions to oil and gas properties ($1,094 million) and decreased proceeds from sales of oil and gas properties ($51 million), partially offset by favorable changes in working capital related to investing activities ($125 million). Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used in financing activities of $299 million in 2006 increased $227 million compared to 2005. Cash used by financing activities for 2006 included repayments of long-term debt borrowings ($317 million), cash dividend payments ($60 million) and redemption of preferred stock, including premium paid ($50 million). Cash provided by financing activities for 2006 included borrowing under a revolving credit facility ($65 million), proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan ($36 million) and excess tax benefits from stock-based compensation expenses ($28 million).

J005 compared to 2004.

Net cash provided by operating activities of $2,369 million in 2005 increased $925 million as compared to 2004 primarily reflecting an increase in wellhead revenues ($1,306 million), a favorable change in the net cash flows from settlement of financial commodity derivative contracts ($93 million) and favorable changes in working capital and other liabilities ($35 million), partially offset by an increase in cash operating expenses ($217 million) and an increase in cash paid for income taxes ($279 million).

Net cash used in investing activities of $1,678 million in 2005 increased by $281 million as compared to 2004 due primarily to increased additions to oil and gas properties ($308 million) and unfavorable changes in working capital related to investing activities ($28 million), partially offset by an increase in proceeds from the sale of oil and gas properties in 2005 ($40 million) and the sale of part of EOG's interest in the N2000 ammonia plant in 2005 ($18 million). Changes in Components of Working Capital Associated with Investing Activities included changes in accounts payable associated with the accrual of exploration and development expenditures and changes in inventories which represent material and equipment used in drilling and related activities.

Cash used in financing activities of $72 million in 2005 increased $29 million as compared to 2004. Cash provided by financing activities for 2005 included a long-term debt borrowing ($250 million) and proceeds from sales of treasury stock attributable to employee stock option exercises and the employee stock purchase plan ($65 million). Cash used by financing activities for 2005 included repayments of long-term debt borrowings ($343 million) and cash dividend payments ($43 million).

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Total Exploration and Development Expenditures

The table below sets out components of total exploration and development expenditures for the years ended December 31, 2006, 2005 and 2004, along with the total budgeted for 2007, excluding acquisitions (in millions):

	Actual			Budgeted 2007 (excluding acquisitions)
	2006	2005	2004	
Expenditure Category				
Capital				
Drilling and Facilities	$2,472	$1,458	$1,120	
Leasehold Acquisitions	225	131	143	
Producing Property Acquisitions	22	56	52	
Capitalized Interest	20	15	10	
Subtotal	2,739	1,660	1,325	
Exploration Costs	155	133	94	

Dry Hole Costs	80	65	92	
Exploration and Development Expenditures	2,974	1,858	1,511	Approximately $3,400
Asset Retirement Costs	22	20	16	
Deferred Income Tax on Acquired Properties	-	-	(17)	
Total Exploration and Development Expenditures	$2,996	$1,878	$ 1,510	

Exploration and development expenditures of $2,974 million for 2006 were $1,116 million higher than the prior year due primarily to increased drilling and facilities expenditures of $1,014 million resulting from higher drilling and facilities expenditures in the United States ($843 million), Trinidad ($79 million), Canada ($57 million) and the United Kingdom ($13 million); increased lease acquisitions in the United States ($74 million) and Canada ($16 million); and changes in the Canadian exchange rate ($28 million). The 2006 exploration and development expenditures of $2,974 million includes $2,228 million in development, $704 million in exploration, $22 million in property acquisitions and $20 million in capitalized interest. The 2005 exploration and development expenditures of $1,858 million includes $1,300 million in development, $487 million in exploration, $56 million in property acquisitions and $15 million in capitalized interest. The 2004 exploration and development expenditures of $1,511 million includes $1,009 million in development, $440 million in exploration, $52 million in property acquisitions and $10 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad and the United Kingdom, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

During 2006, EOG recognized gains on mark-to-market financial commodity derivative contracts of $334 million, which included realized gains of $215 million. During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. (See Note 11 to Consolidated Financial Statements.)

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Presented below is a comprehensive summary of EOG's 2007 natural gas and crude oil financial price swap contracts at February 26, 2007, with prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), as applicable, and notional volumes in million British thermal units per day (MMBtud) and in barrels per day (Bbld), as applicable. Currently, EOG is not a party to any financial collar contracts. EOG accounts for these price swap contracts using the mark-to-market accounting method.

Financial Price Swap Contracts

	Natural Gas		Crude Oil	
Month	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
January (closed)	120,000	$10.91	4,000	$78.42
February (1)	120,000	10.93	4,000	78.55
March	120,000	10.75	4,000	78.58
April	120,000	8.81	4,000	78.57
May	120,000	8.65	4,000	78.50
June	120,000	8.74	4,000	78.40
July	120,000	8.84	4,000	78.28
August	120,000	8.92	4,000	78.16
September	120,000	9.00	4,000	78.03
October	120,000	9.14	4,000	77.91
November	120,000	9.94	4,000	77.75
December	120,000	10.70	4,000	77.57

(1) The natural gas contracts for February 2007 are closed. The crude oil contracts for February 2007 will close on February 28, 2007.

Financing

EOG's debt-to-total capitalization ratio was 12% as of December 31, 2006 compared to 19% as of December 31, 2005.

During 2006, total debt decreased $252 million to $733 million (see Note 2 to Consolidated Financial Statements). The estimated fair value of EOG's debt at December 31, 2006 and 2005 was $754 million and $1,025 million, respectively. The estimated fair value was based upon quoted market prices and, where such prices were not available, upon interest rates available to EOG at year-end. EOG's debt is primarily at fixed interest rates. At December 31, 2006, a 1% decline in interest rates would result in a $39 million increase in the estimated fair value of the fixed rate obligations (see Note 11 to Consolidated Financial Statements).

During 2006 and 2005, EOG utilized cash provided by operating activities and commercial paper to fund its operations. While EOG maintains a $600 million commercial paper program, the maximum outstanding at any time during 2006 was $172 million, and the amount outstanding at year-end was zero. EOG considers this excess availability, which is backed by the $600 million Revolving Credit Agreement with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, combined with approximately $688 million of availability under its shelf registration described below, to be ample to meet its ongoing operating needs.

During 2006, EOG repaid the $126 million, 6.70% Notes due in 2006 primarily with cash generated from operating activities. In 2006, a foreign subsidiary of EOG repaid $190 million of the $250 million borrowed in 2005 (see Note 2 to Consolidated Financial Statements). The foreign subsidiary has the option to pay off the remaining $60 million of the $250 million borrowed in 2005 at any time prior to maturity. EOG plans to replace the $98 million, 6.50% Notes due 2007 with other long-term debt.

On October 11, 2006, EOG commenced a cash tender offer to purchase any and all of the 100,000 outstanding shares of the 7.195% Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (Series B), at a price of $1,074.01 per share plus accrued and unpaid dividends up to the date of purchase. The tender offer expired on November 8, 2006, and on November 10, 2006, EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including redemption premium, fees and dividends, of

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$51 million. EOG has included as a component of preferred dividends the $4 million of premium and fees associated with the redemption of the Series B shares. A total of 53,260 shares of the Series B remain outstanding at December 31, 2006.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2006 (in thousands):

Contractual Obligations (1)	Total	2007	2008 - 2010	2011 - 2012	2013 & Beyond
Long-Term Debt	$ 733,442	$ -	$125,000	$318,442	$ 290,000
Non-cancelable Operating Leases	189,533	17,627	50,927	29,141	91,838
Interest Payments on Long-Term Debt	351,416	45,441	102,712	48,270	154,993
Pipeline Transportation Service Commitments (2)	1,675,148	78,005	478,822	342,990	775,331
Drilling Rig Commitments (3)	472,253	229,991	240,372	1,890	-
Seismic Purchase Obligations	2,322	2,322	-	-	-
Other Purchase Obligations	36,602	35,916	686	-	-
Total Contractual	$3,460,716	$409,302	$998,519	$740,733	$1,312,162

Obligations

(1) This table does not include the liability for dismantlement, abandonment and restoration costs of oil and gas properties. In addition,
this table does not include EOG's pension or postretirement benefit obligations (see Note 6 to Consolidated Financial Statements).
(2) Amounts shown are based on current pipeline transportation rates and the foreign currency exchange rates used to convert Canadian
Dollars and British Pounds into United States Dollars at December 31, 2006. Management does not believe that any future changes
in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results
of operations of EOG.
(3) Amounts shown represent minimum future expenditures for drilling rig services.

Shelf Registration

On September 15, 2006, EOG filed an automatically effective shelf registration statement on Form S-3 (New Registration Statement) for the offer and sale from time to time of up to $688,237,500 of EOG's debt securities, preferred stock and common stock. The New Registration Statement was filed to replace EOG's existing shelf registration statement declared effective by the SEC in October 2000, under which EOG had sold no securities. As of February 26, 2007, the entire amount registered remains available under the New Registration Statement.

Off-Balance Sheet Arrangements

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

Foreign Currency Exchange Rate Risk

During 2006, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad and the United Kingdom. The foreign currency most significant to EOG's operations during 2006 was the Canadian Dollar. The fluctuation of the Canadian Dollar in 2006 impacted both the revenues and expenses of EOG's Canadian subsidiaries. However, since the Canadian natural gas prices are largely correlated to United States prices, the changes in the Canadian currency exchange rate have less of an impact on the Canadian revenues than the Canadian expenses. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against the foreign currency exchange rate risk.

Effective March 9, 2004, EOG entered into a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the notes offered by one of the Canadian subsidiaries on the same date (see Note 2 to Consolidated Financial Statements). EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. Under those provisions, as of December 31, 2006, EOG recorded the fair value of the swap of $36 million in Other Liabilities on the Consolidated Balance Sheets. Changes in the fair value of the foreign currency swap resulted in no net impact to Net Income Available to Common on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap transaction resulted in a negative change of $1 million for the year ended December 31, 2006. This amount is included in Accumulated Other Comprehensive Income in the Shareholders' Equity section of the Consolidated Balance Sheets.

Outlook

Natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of future United States and Canada natural gas and crude oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. Being primarily a natural gas producer, EOG is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate prices. Longer term natural gas prices will be determined by the supply and demand for natural gas as well as the prices of competing fuels, such as oil and coal.

Assuming a totally unhedged position for 2007, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2007 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $27 million for net income and operating cash flow. EOG's price sensitivity in 2007 for each $1.00 per barrel change in wellhead crude oil price is approximately $6 million for net income and operating cash flow. For information regarding EOG's natural gas and crude oil hedge position as of December 31, 2006, see Note 11 to Consolidated Financial Statements.

EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States and Canada. However, in order to diversify its overall asset portfolio and as a result of its overall success realized in Trinidad and the United Kingdom North Sea, EOG anticipates expending a portion of its available funds in the further development of opportunities outside the United States and Canada. In addition, EOG expects to conduct exploratory activity in other areas outside of the United States and Canada and will continue to evaluate the potential for involvement in additional exploitation type opportunities. Budgeted 2007 exploration and development expenditures, excluding acquisitions, are approximately $3.4 billion and are structured to maintain the flexibility necessary under EOG's strategy of funding its exploration, development, exploitation and acquisition activities primarily from available internally generated cash flow.

The level of exploration and development expenditures may vary in 2007 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, EOG believes net operating cash flow and available financing alternatives in 2007 will be sufficient to fund its net investing cash requirements for the year. However, EOG has significant flexibility with respect to its financing alternatives and adjustment of its exploration, exploitation, development and acquisition expenditure plans if circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad and the United Kingdom, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Environmental Regulations

Various foreign, federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect EOG's operations and costs as a result of their effect on natural gas and crude oil exploration, development and production operations and could cause EOG to incur remediation or other corrective action costs in connection with a release of regulated substances, including crude oil, into the environment. In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators.

In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG owns an interest but is not the operator. Compliance with such

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laws and regulations increases EOG's overall cost of business, but has not had a material adverse effect on EOG's operations or financial condition. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts that are material in relation to its total exploration and development expenditure program in order to comply with environmental laws and regulations but, inasmuch as such laws and regulations are frequently changed, EOG is unable to predict the ultimate cost of compliance. EOG also could incur costs related to the clean up of sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such sites.

Summary of Critical Accounting Policies

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

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves, which directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Oil and Gas Exploration Costs

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. Exploratory drilling costs are capitalized when drilling is complete if it is determined that there is economic producibility supported by either actual production, a conclusive formation test or by certain technical data if the discovery is located offshore in the Gulf of Mexico. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of December 31, 2006 and 2005, EOG had exploratory drilling costs related to two projects that have been deferred for more than one year (see Note 15 to Consolidated Financial Statements). These costs meet the accounting requirements outlined above for continued capitalization. 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.

Impairments

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

When circumstances indicate that a producing asset may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future

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undiscounted cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

Depreciation, Depletion and Amortization for Oil and Gas Properties

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

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

Assets are grouped in accordance with paragraph 30 of SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

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

Stock-Based Compensation

Effective January 1, 2006, EOG accounts for stock-based compensation under the provisions of SFAS No. 123(R), "Share Based Payment." SFAS No. 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award, eliminating the exception to account for such awards using the intrinsic method previously allowable under APB Opinion No. 25, "Accounting for Stock Issued to Employees." In applying the provisions of SFAS 123(R), judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. Assumptions regarding expected volatility of

EOG's common stock, the level of risk free interest rates, expected dividend yields on EOG's stock, the expected term of the awards and other valuation inputs are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized in the Consolidated Statements of Income and Comprehensive Income.

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Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical facts, including, among others, statements regarding EOG's future financial position, business strategy, budgets, reserve information, projected levels of production, projected costs and plans and objectives of management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "strategy," "intend," "plan," "target" and "believe" or the negative of those terms or other variations of them or by comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning future operating results, the ability to replace or increase reserves or to increase production, or the ability to generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes its expectations reflected in forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will be achieved. Important factors that could cause actual results to differ materially from the expectations reflected in the forward-looking statements include, among others: the timing and extent of changes in commodity prices for crude oil, natural gas and related products, foreign currency exchange rates and interest rates; the timing and impact of liquefied natural gas imports and changes in demand or prices for ammonia or methanol; the extent and effect of any hedging activities engaged in by EOG; the extent of EOG's success in discovering, developing, marketing and producing reserves and in acquiring oil and gas properties; the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise; the availability and cost of drilling rigs, experienced drilling crews, materials and equipment used in well completions, and tubular steel; the availability, terms and timing of governmental and other permits and rights of way; the availability of pipeline transportation capacity; the availability of compression uplift capacity; the extent to which EOG can economically develop its Barnett Shale acreage outside of Johnson County, Texas; whether EOG is successful in its efforts to more densely develop its acreage in the Barnett Shale and other production areas; political developments around the world; acts of war and terrorism and responses to these acts; weather; and financial market conditions. In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements might not occur. Forward-looking statements speak only as of the date made and EOG undertakes no obligation to update or revise its forward-looking statements, whether as a result of new information, future events or otherwise.

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ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

EOG's exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk is discussed in the Derivative Transactions, Financing, Foreign Currency Exchange Rate Risk and Outlook sections of "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. *Financial Statements and Supplementary Data*

Information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

ITEM 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

ITEM 9A. *Controls and Procedures*

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this report (Evaluation Date). Based on this evaluation, the principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date to ensure that information that is required to be disclosed by EOG in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EOG's management as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining effective internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Exchange Act). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2006. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework.* Based on this assessment, management believes that, as of December 31, 2006, EOG's internal control over financial reporting is effective based on those criteria. EOG's assessment also appears on page F-2.

EOG's independent registered public accounting firm has issued an audit report on EOG's assessment of its internal control over financial reporting. This report begins on page F-3.

There were no changes in EOG's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

ITEM 9B. *Other Information*

None.

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PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance*

Directors and Executive Officers of the Registrant.

The information required by this Item regarding directors is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Election of Directors" of Item 1.

Audit Committee and Corporate Governance Related Matters and Code of Ethics for the CEO and CFO.

The information required by this Item regarding audit committee related matters is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Corporate Governance."

Compliance with Section 16(a) of the Exchange Act.

The information required by this Item regarding compliance with Section 16(a) of the Exchange Act is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Section 16(a) Beneficial Ownership Reporting Compliance."

ITEM 11. *Executive Compensation*

The information required by this Item is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the captions "Executive Compensation " and "Director Compensation."

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Voting Rights and Principal Stockholders."

Equity Compensation Plan Information

EOG has various plans under which employees and nonemployee members of the Board of Directors of EOG and its subsidiaries have been or may be granted certain equity compensation consisting of stock options, restricted stock, restricted stock units and phantom stock. The 1992 Stock Plan, the 1993 Nonemployee Directors Stock Option Plan and the Employee Stock Purchase Plan have been approved by security holders. Plans that have not been approved by security holders are described below. The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by security holders and those plans not approved by security holders as of December 31, 2006.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity Compensation Plans Approved by Security Holders	8,184,012	$43.40	3,135,549[(1) (2)]
Equity Compensation Plans Not Approved by Security Holders	4,329,301	$20.18[(3)]	131,667[(4) (5)]
Total	12,513,313	$35.44[(3)]	3,267,216

(1) Of these securities, 315,762 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 1,254,466 could be issued as restricted stock or restricted stock units under the 1992 Stock Plan.
(3) Weighted-average exercise price does not include 62,098 phantom stock units in the 1996 Deferral Plan which are

included in column (a).

(4) Of these securities, 34,051 phantom stock units remain available for issuance under the 1996 Deferral Plan.

(5) Of these securities, 97,616 could be issued as restricted stock or restricted stock units under the 1994 Stock Plan.

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Stock Plan Not Approved by Security Holders.

The Board of Directors of EOG approved the 1994 Stock Plan, which provides equity compensation to employees who are not officers within the meaning of Rule 16a-1 of the Securities Exchange Act of 1934, as amended. Under the plan, employees have been or may be granted stock options (rights to purchase shares of EOG common stock at a price not less than the market price of the stock at the date of grant). Stock options vest either immediately at the date of grant or up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options granted under the plan have not exceeded a maximum term of 10 years. Employees have also been or may be granted shares of restricted stock and/or restricted stock units without cost to the employee. The shares and units granted vest to the employee at various times ranging from one to five years as defined in individual grant agreements. Upon vesting, restricted shares are released to the employee. Upon vesting, each restricted stock unit is converted into one share of EOG common stock and released to the employee.

Deferral Plan Phantom Stock Account.

The Board of Directors of EOG approved the 1996 Deferral Plan, under which payment of base salary, annual bonus and directors fees may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if shares of EOG common stock were purchased at the closing stock price on the date of deferral. Dividends are credited quarterly and treated as if reinvested in EOG common stock. Payment of the phantom stock account is made in actual shares of EOG common stock. A total of 120,000 shares have been registered for issuance under the plan. As of December 31, 2006, 85,949 phantom stock units had been issued and 34,051 units remained available for issuance under the plan.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence*

Information regarding Certain Relationships and Related Transactions is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Related Party Transactions."

Information regarding Director Independence is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Corporate Governance."

ITEM 14. *Principal Accounting Fees and Services*

Information regarding auditor fees, audit-related fees, tax fees and all other fees and services billed by the principal accountant is incorporated by reference from the Proxy Statement to be filed within 120 days after December 31, 2006, under the caption "Ratification of Appointment of Auditors - General" of Item 2.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedule

See "Index to Financial Statements" set forth on page F-1.

(a)(3) Exhibits

See pages E-1 through E-4 for a listing of the exhibits.

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EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

Other financial statement schedules have been omitted because they are inapplicable or the information required therein is included elsewhere in the consolidated financial statements or notes thereto.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

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

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

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

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2006. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework*. These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment, management believes that, as of December 31, 2006, EOG's internal control over financial reporting is effective based on those criteria.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements and management's assessment of the effectiveness of EOG's internal control over financial reporting, and to issue a report thereon. In the conduct of the audit, Deloitte & Touche LLP was given unrestricted access to all financial records and related data including minutes of all meetings of shareholders, the Board of Directors and committees of the Board. Management believes that all representations made to Deloitte & Touche LLP during the audit were valid and appropriate. Their audit was made in accordance with standards of the Public Company Accounting Oversight Board (United States) and included a review of the system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on the consolidated financial statements, management's assessment of EOG's internal control over financial reporting and the effectiveness of EOG's internal control over financial reporting. Their report begins on page F-3.

MARK G. PAPA	EDMUND P. SEGNER, III	TIMOTHY K. DRIGGERS
Chairman of the Board and	Senior Executive Vice President and	Vice President and Chief
Chief Executive Officer	Chief of Staff	Accounting Officer

Houston, Texas
February 26, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. and subsidiaries (the "Company") as of December 31, 2006 and 2005, 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, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited management's assessment, included in the accompanying Management's Responsibility for Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule, an opinion on management's assessment, and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

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

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EOG Resources, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 6 to the consolidated financial statements, on January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (R), "Share Based Payment."

DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2007

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(In Thousands, Except Per Share Data)

Year Ended December 31	2006	2005	2004
Net Operating Revenues			
Natural Gas	$2,803,245	$2,938,917	$1,842,316
Crude Oil, Condensate and Natural Gas Liquids	761,580	668,073	458,446

Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	334,260	10,475	(33,449)
Other, Net	5,330	2,748	3,912
Total	3,904,415	3,620,213	2,271,225
Operating Expenses			
Lease and Well	372,895	286,417	219,982
Transportation Costs	110,328	86,938	51,104
Exploration Costs	155,008	133,116	93,941
Dry Hole Costs	79,567	64,812	92,142
Impairments	108,258	77,932	81,530
Depreciation, Depletion and Amortization	817,089	654,258	504,403
General and Administrative	164,981	125,918	115,013
Taxes Other Than Income	200,863	199,007	133,915
Total	2,008,989	1,628,398	1,292,030
Operating Income	1,895,426	1,991,815	979,195
Other Income, Net	60,373	35,828	9,945
Income Before Interest Expense and Income Taxes	1,955,799	2,027,643	989,140
Interest Expense			
Incurred	63,058	77,102	72,759
Capitalized	(19,900)	(14,596)	(9,631)
Net Interest	43,158	62,506	63,128

Expense			
Income Before Income Taxes	1,912,641	1,965,137	926,012
Income Tax Provision	612,756	705,561	301,157
Net Income	1,299,885	1,259,576	624,855
Preferred Stock Dividends	10,995	7,432	10,892
Net Income Available to Common	$ 1,288,890	$ 1,252,144	$ 613,963
Net Income Per Share Available to Common			
Basic	$ 5.33	$ 5.24	$ 2.63
Diluted	$ 5.24	$ 5.13	$ 2.58
Average Number of Common Shares			
Basic	241,782	238,797	233,751
Diluted	246,100	243,975	238,376
Comprehensive Income			
Net Income	$ 1,299,885	$ 1,259,576	$ 624,855
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	883	34,074	77,925
Foreign Currency Swap Transaction	(219)	(7,567)	(5,816)
	(605)	2,615	1,972

Income Tax Related to Foreign Currency Swap Transaction			
Comprehensive Income	$1,299,944	$1,288,698	$ 698,936

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

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EOG RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Data)

At December 31	2006	2005
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 218,255	$ 643,811
Accounts Receivable, Net	754,134	762,207
Inventories	113,591	63,215
Assets from Price Risk Management Activities	130,612	11,415
Income Taxes Receivable	94,311	255
Deferred Income Taxes	-	24,376
Other	39,177	57,959
Total	1,350,080	1,563,238
Oil and Gas Properties (Successful Efforts Method)	13,893,851	11,173,389
Less: Accumulated Depreciation, Depletion and Amortization	(5,949,804)	(5,086,210)
	7,944,047	6,087,179

Net Oil and Gas Properties		
Other Assets	108,033	102,903
Total Assets	$ 9,402,160	$ 7,753,320

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities		
Accounts Payable	$ 896,572	$ 679,548
Accrued Taxes Payable	130,984	140,902
Dividends Payable	14,718	9,912
Deferred Income Taxes	144,615	164,659
Current Portion of Long-Term Debt	-	126,075
Other	68,123	50,945
Total	1,255,012	1,172,041
Long-Term Debt	733,442	858,992
Other Liabilities	300,907	283,407
Deferred Income Taxes	1,513,128	1,122,588
Shareholders' Equity		
Preferred Stock, $0.01 Par, 10,000,000 Shares Authorized:		
Series B, Cumulative, $1,000 Liquidation Preference Per Share, 53,260 Shares Outstanding at December 31, 2006, and		

100,000 Shares Outstanding at December 31, 2005	52,887	99,062
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 249,460,000 Shares Issued	202,495	202,495
Additional Paid in Capital	129,986	84,705
Unearned Compensation	-	(36,246)
Accumulated Other Comprehensive Income	176,704	177,137
Retained Earnings	5,151,034	3,920,483
Common Stock Held in Treasury, 5,724,959 Shares at December 31, 2006 and 7,385,862 Shares at December 31, 2005	(113,435)	(131,344)
Total Shareholders' Equity	5,599,671	4,316,292
Total Liabilities and Shareholders' Equity	$ 9,402,160	$ 7,753,320

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In Thousands, Except Per Share Data)

	Preferred Stock	Common Stock	Additional Paid In Capital	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Shareholders' Equity
Balance at December 31, 2003	$148,416	$201,247	$ 1,625	$(23,473)	$ 73,934	$2,121,214	$(299,582)	$2,223,381
Net Income	-	-	-	-	-	624,855	-	624,855
Redemption of Preferred Stock, $100,000 Per Share	(50,000)	-	-	-	-	-	-	(50,000)
Amortization of Preferred Stock Discount	410	-	-	-	-	(410)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,482)	-	(10,482)
Common Stock Dividends Declared, $0.12 Per Share	-	-	-	-	-	(28,332)	-	(28,332)
Translation Adjustment	-	-	-	-	77,925	-	-	77,925
Treasury Stock Purchased	-	-	-	-	-	-	(9,565)	(9,565)
Foreign Currency Swap Transaction	-	-	-	-	(3,844)	-	-	(3,844)
Treasury Stock Issued Under Stock Plans	-	-	(20,876)	-	-	-	103,403	82,527
Tax Benefits from Stock Options Exercised	-	-	29,396	-	-	-	-	29,396
Restricted Stock and Units	-	-	10,902	(15,951)	-	-	5,049	-
Amortization of Unearned Compensation	-	-	-	9,563	-	-	-	9,563
Balance at December 31, 2004	98,826	201,247	21,047	(29,861)	148,015	2,706,845	(200,695)	2,945,424
Net Income	-	-	-	-	-	1,259,576	-	1,259,576
Common Stock Issued - Stock Split	-	1,248	(1,248)	-	-	-	-	-

Amortization of Preferred Stock Discount	236	-	-	-	-	(236)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(7,196)	-	(7,196)
Common Stock Dividends Declared, $0.16 Per Share	-	-	-	-	-	(38,506)	-	(38,506)
Translation Adjustment	-	-	-	-	34,074	-	-	34,074
Foreign Currency Swap Transaction	-	-	-	-	(4,952)	-	-	(4,952)
Treasury Stock Issued Under Stock Plans	-	-	2,157	-	-	-	61,209	63,366
Tax Benefits from Stock Options Exercised	-	-	50,880	-	-	-	-	50,880
Restricted Stock and Units	-	-	11,080	(18,573)	-	-	7,493	-
Amortization of Unearned Compensation	-	-	-	12,188	-	-	-	12,188
Treasury Stock Issued as Compensation	-	-	789	-	-	-	649	1,438
Balance at December 31, 2005	99,062	202,495	84,705	(36,246)	177,137	3,920,483	(131,344)	4,316,292
Net Income	-	-	-	-	-	1,299,885	-	1,299,885
Redemption of Preferred Stock	(46,740)	-	-	-	-	-	-	(46,740)
Adjustment to Reflect Adoption of FASB Statement 123 (R)	-	-	(36,246)	36,246	-	-	-	-
Amortization of Preferred Stock Discount	565	-	-	-	-	(565)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(10,430)	-	(10,430)
Common Stock Dividends								

Declared, $0.24 Per Share	-	-	-	-	-	(58,339)	-	(58,339)
Translation Adjustment	-	-	-	-	883	-	-	883
Foreign Currency Swap Transaction	-	-	-	-	(824)	-	-	(824)
Treasury Stock Purchased	-	-	-	-	-	-	-	-
Treasury Stock Issued Under Stock Plans	-	-	9,623	-	-	-	8,945	18,568
Tax Benefits from Stock Options Exercised and Restricted Stock and Units Released	-	-	30,993	-	-	-	-	30,993
Restricted Stock and Units	-	-	(8,964)	-	-	-	8,964	-
Expense on Stock-Based Compensation	-	-	49,875	-	-	-	-	49,875
Adjustment to Initially Apply FASB Statement 158, Net of Tax	-	-	-	-	(492)	-	-	(492)
Balance at December 31, 2006	$ 52,887	$202,495	$129,986	$ -	$176,704	$5,151,034	$(113,435)	$5,599,671

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

Year Ended December 31	2006	2005	2004
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash			

Provided by Operating Activities:			
Net Income	$ 1,299,885	$ 1,259,576	$ 624,855
Items Not Requiring Cash			
Depreciation, Depletion and Amortization	817,089	654,258	504,403
Impairments	108,258	77,932	81,530
Stock-Based Compensation Expenses	49,875	12,187	9,563
Deferred Income Taxes	385,842	270,291	204,231
Other, Net	(10,025)	(2,545)	(4,983)
Dry Hole Costs	79,567	64,812	92,142
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	(334,260)	(10,475)	33,449
Realized Gains (Losses)	215,063	9,807	(82,644)
Collar Premium	-	-	(520)
Tax Benefits from Stock Options Exercised	-	50,880	29,396
Other, Net	12,291	(5,086)	537
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	9,905	(315,557)	(151,799)
Inventories	(50,370)	(23,085)	(17,898)
Accounts Payable	222,012	248,411	136,716
Accrued Taxes Payable	(106,324)	88,151	18,197
Other Liabilities	(8,766)	(1,213)	(1,764)
Other, Net	12,349	(10,347)	(2,683)
Changes in Components of Working			

Capital Associated with Investing and Financing Activities	(123,838)	1,429	(28,381)
Net Cash Provided by Operating Activities	2,578,553	2,369,426	1,444,347
Investing Cash Flows			
Additions to Oil and Gas Properties	(2,819,230)	(1,724,763)	(1,416,684)
Proceeds from Sales of Assets	20,041	70,987	13,459
Changes in Components of Working Capital Associated with Investing Activities	123,890	(1,538)	26,788
Other, Net	(35,074)	(22,794)	(20,471)
Net Cash Used in Investing Activities	(2,710,373)	(1,678,108)	(1,396,908)
Financing Cash Flows			
Net Commercial Paper and Revolving Credit Facility Borrowings (Repayments)	65,000	(91,800)	(6,250)
Long-Term Debt Borrowings	-	250,000	150,000
Long-Term Debt Repayments	(316,625)	(250,755)	(175,000)
Dividends Paid	(60,443)	(42,986)	(37,595)
Excess Tax Benefits from Stock-Based Compensation Expenses	28,188	-	-
Redemption of Preferred Stock	(50,199)	-	(50,000)

Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	36,033	64,668	75,510
Other, Net	(836)	(1,437)	97
Net Cash Used in Financing Activities	(298,882)	(72,310)	(43,238)
Effect of Exchange Rate Changes on Cash	5,146	3,823	12,336
(Decrease) Increase in Cash and Cash Equivalents	(425,556)	622,831	16,537
Cash and Cash Equivalents at Beginning of Year	643,811	20,980	4,443
Cash and Cash Equivalents at End of Year	$ 218,255	$ 643,811	$ 20,980

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

EOG RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Principles of Consolidation.

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

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

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

On February 2, 2005, EOG announced that the Board of Directors (Board) had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and issued on March 1, 2005. All share and per share data in the financial statements and accompanying footnotes for all periods have been restated to reflect the two-for-one stock split paid to common shareholders.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt. The carrying values of cash and cash equivalents, marketable securities, commodity derivative contracts, accounts receivable and accounts payable approximate fair value (see Note 11).

Cash and Cash Equivalents.

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

Oil and Gas Operations.

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

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

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. Exploratory drilling costs are capitalized when drilling is complete if it is determined that there is economic producibility supported by either actual production, a conclusive formation test or by certain technical data if the discovery is located offshore in the Gulf of Mexico. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of December 31, 2006 and 2005, EOG had exploratory drilling costs related to two projects that have been deferred for more than one year (see Note 15). These costs meet the accounting requirements outlined above for continued capitalization. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of natural gas and crude oil, are capitalized.

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

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

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

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

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

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

Capitalized Interest Costs.

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

Accounting for Price Risk Management Activities.

EOG accounts for its price risk management activities under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS Nos. 137, 138 and 149. The statement establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ending December 31, 2006, EOG elected not to designate any of its commodity price risk management activities as accounting hedges under SFAS No. 133, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change. The gains or losses are recorded in Gains (Losses) on Mark-to-Market Commodity Derivative Contracts. The related cash flow impact is reflected as cash flows from operating activities (see Note 11).

Income Taxes.

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

Foreign Currency Translation.

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

Net Income Per Share.

In accordance with the provisions of SFAS No. 128, "Earnings per Share," basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted net income per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities (see Note 8).

Stock-Based Compensation. Effective January 1, 2006, EOG accounts for stock-based compensation under the provisions of SFAS No. 123(R), "Share Based Payment." EOG adopted SFAS No. 123(R) using the modified prospective application method and has therefore not restated its previously issued financial statements. SFAS No. 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award, eliminating the exception to account for such awards using the intrinsic method previously allowable under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." Prior to the adoption of SFAS No. 123(R), EOG included tax benefits resulting from the exercise of stock options in the operating activities section of the Consolidated Statements of Cash Flows. SFAS No. 123(R) requires that cash flows provided by excess tax benefits from stock-based compensation deductions be reflected in the financing activities section of the Consolidated Statements of Cash Flows and Unearned Compensation previously included separately in Shareholders' Equity be written off against Additional Paid in Capital at the date of adoption.

EOG has adopted the alternative transition method prescribed in FASB Staff Position (FSP) FAS 123R-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," for calculating the beginning balance of excess tax benefits related to employee stock-based compensation included in additional paid in capital (APIC Pool). The APIC Pool represents the amount of tax benefits available to absorb future tax deficiencies that may result in connection with employee stock-based compensation. FSP FAS 123R-3 also provides a simplified method to determine the subsequent impact on the APIC Pool of stock-based compensation awards that are fully vested at the date of adoption of SFAS 123(R).

Recently Issued Accounting Standards and Developments.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R)." SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its balance sheet. The funded status is defined as the difference between the fair value of plan assets and the projected benefit obligation (for pension plans) or the accumulated postretirement benefit obligation (for other postretirement benefit plans). SFAS No. 158 also requires that actuarial gains and losses and changes in prior service costs not included in net periodic pension costs be included, net of tax, as a component of other comprehensive income. The statement does not affect the determination of net periodic benefit costs included in the income statement. SFAS No. 158 also requires that an employer measure defined benefit plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position.

The requirement to recognize the funded status of defined benefit plans and to provide required disclosures is effective as of the end of fiscal years ending after December 15, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end is effective for fiscal years ending after December 15, 2008. The adoption of the recognition and disclosure provisions of SFAS No. 158 did not have a material impact on EOG's financial statements. EOG does not expect that the adoption of the measurement date provisions of SFAS No. 158 will have a material impact on EOG's financial statements since plan assets and benefit obligations are currently measured as of the date of EOG's fiscal year end.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 provides a definition of fair value and provides a framework for measuring fair value. The standard also requires additional disclosures on the use of fair value in measuring assets and liabilities. SFAS No. 157 establishes a fair value hierarchy and requires disclosure of fair value measurements within that hierarchy. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those years. EOG is assessing the impact, if any, that the adoption of SFAS No. 157 will have on its financial statements.

During July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN No. 48 addresses the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes specific criteria for the financial statement recognition and measurement of the tax effects of a position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition of previously recognized tax benefits, classification of tax liabilities on the balance sheet, recording interest and penalties on tax underpayments, accounting in interim periods and disclosure requirements. FIN No. 48 is effective for fiscal periods beginning after December 15, 2006. EOG adopted FIN No. 48 as of January 1, 2007. The cumulative effect of applying the provisions of FIN No. 48 will be reported as an adjustment to the opening balance of retained earnings for 2007. EOG expects to record an adjustment increasing retained earnings by approximately $10 million.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF Issue 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. EOG presents purchase and sale activities related to its marketing activities on a net basis in the Consolidated Statements of Income and Comprehensive Income. The adoption of EITF Issue No. 04-13 did not have a material impact on EOG's financial statements.

In March 2005, the FASB issued FIN No. 47, "Accounting for Conditional Asset Retirement Obligations." The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN No. 47 is effective for fiscal years ending after December 15, 2005. The adoption of FIN No. 47 did not have a material impact on EOG's financial statements.

2. Long-Term Debt

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

	2006	2005
6.70% Notes due 2006	$ -	$ 126,075
6.50% Notes due 2007	98,442	98,992
6.65% Notes due 2028	140,000	140,000
Subsidiary Senior Unsecured Term Loan Facility due 2008	60,000	250,000
Subsidiary Revolving Credit Facility due 2009	65,000	-
7.00% Subsidiary Debt due 2011	220,000	220,000

4.75% Subsidiary Debt due 2014		150,000		150,000
		733,442		985,067
Less: Current Portion of Long-Term Debt		-		126,075
Total	$	733,442	$	858,992

At December 31, 2006, the aggregate annual maturities of long-term debt were $98 million in 2007, $60 million in 2008, $65 million in 2009, zero in 2010 and $220 million in 2011. At December 31, 2006, the $98 million principal amount of the 6.50% Notes due 2007 was classified as long-term debt based upon EOG's intent and ability to ultimately replace such amount with other long-term debt.

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On November 15, 2006, EOG repaid the remaining principal amount of its 6.70% Notes due November 15, 2006 at par plus accrued and unpaid interest through the maturity date.

On May 12, 2006, EOG Resources Trinidad Limited, a wholly-owned foreign subsidiary of EOG, entered into a 3-year $75 million Revolving Credit Agreement (Credit Agreement). Borrowings under the Credit Agreement accrue interest based, at EOG's option, on either a London InterBank Offering Rate (LIBOR) plus an applicable margin or the base rate of the Credit Agreement's administrative agent. EOG had $65 million outstanding under the Credit Agreement at December 31, 2006. The applicable interest rate at December 31, 2006 was 5.78%. The weighted average interest rate for the amounts outstanding during the year ended December 31, 2006 was 5.90%.

In accordance with notice delivered to holders on November 1, 2005, EOG redeemed the remaining $174 million outstanding principal amount of its 6.00% Notes due 2008 (2008 Notes) on December 5, 2005, at a redemption price of $1,039.22 per each $1,000.00 of principal amount, plus accrued and unpaid interest through the redemption date. The redemption was made in accordance with terms of the indenture and the officer's certificate establishing the terms of the 2008 Notes. In connection with the redemption, EOG recognized a loss on extinguishment of debt in the amount of $8 million, included in Net Interest Expense, representing prepaid interest and the write-off of deferred bond issuance costs.

In October 2005, EOGI International Company (EOGI), a wholly-owned foreign subsidiary of EOG, entered into a $600 million, 3-year unsecured Senior Term Loan Agreement (Term Loan Agreement) with The Bank of Nova Scotia, as Administrative Agent, and certain banks, as lenders. All borrowings under this agreement were to be made as term loans and be guaranteed by EOG. Proceeds from the Term Loan Agreement were to be used for general corporate purposes, including funding distributions ultimately to EOG from its foreign subsidiaries to realize a benefit of the favorable United States tax legislation regarding repatriation of foreign earnings under the American Jobs Creation Act of 2004. Borrowings up to $600 million under the Term Loan Agreement were available in multiple drawings through December 31, 2005, and prior to such date, EOGI elected to borrow $250 million, which was used to fund the distributions ultimately to EOG as described above. Subsequent to December 31, 2005, borrowing capacity under the Term Loan Agreement was reduced to $100 million and such amount was to be available for an additional one-year period. During 2006, EOGI repaid $190 million of the $250 million outstanding balance of the Term Loan Agreement. Effective July 17, 2006, EOG terminated all remaining borrowing capacity under the Term Loan Agreement. Borrowings under the Term Loan Agreement accrue interest based, at EOG's option, on either a LIBOR plus an applicable margin or at the base rate of the Term Loan Agreement's administrative agent. The applicable interest rate for the $60 million outstanding balance at December 31, 2006 was 5.75%. The weighted average interest rate for the amounts outstanding during the year ended December 31, 2006 was 5.46%.

On June 28, 2005, EOG entered into a 5-year $600 million unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. The Agreement was amended on June 21, 2006, effectively extending the scheduled maturity date to June 28, 2011. The Agreement provides for the allocation, at the option of EOG, of up to $75 million each to EOG's United Kingdom subsidiary and one of its Canadian subsidiaries. The Agreement also provides EOG the option to request letters of credit to be issued in an aggregate amount of up to $200 million. Interest accrues on advances based, at EOG's option, on either LIBOR plus an applicable margin (Eurodollar rate) or the base rate of the Agreement's administrative agent. Advances to the Canadian or the United Kingdom subsidiaries, should they occur, would be guaranteed by EOG and would bear interest at a rate calculated in accordance with the Agreement. There are no borrowings or letters of credit currently outstanding under the Agreement. At December 31, 2006, the applicable base rate and Eurodollar rate, had there been an amount borrowed under the Agreement, would have been 8.25% and 5.50%, respectively.

The Agreement, the Term Loan Agreement and the Credit Agreement each contain certain restrictive covenants applicable to EOG, including a financial covenant with a maximum debt-to-total capitalization ratio of 65%. Other than this financial covenant, there are no other financial covenants in EOG's financing agreements. EOG continues to comply with this financial covenant and does not view it as materially restrictive.

During 2005, EOG repaid the remaining $75 million outstanding balance of its $150 million 3-year Senior Unsecured Term Loan Facility with a group of banks with a maturity date of October 30, 2005.

The 6.50% and 6.65% Notes due 2007 and 2028 were issued through public offerings and have effective interest rates of 6.50% to 6.65%. The Subsidiary Debt due 2011 bears interest at a fixed rate of 7.00% and is guaranteed by EOG.

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

Shelf Registration.

On September 15, 2006, EOG filed an automatically effective shelf registration statement on Form S-3 (New Registration Statement) for the offer and sale from time to time of up to $688,237,500 of EOG's debt securities, preferred stock and common stock. The New Registration Statement was filed to replace EOG's existing shelf registration statement declared effective by the SEC in October 2000, under which EOG had sold no securities. As of February 26, 2007, the entire amount registered remains available under the New Registration Statement.

Fair Value of Current and Long-Term Debt.

At December 31, 2006 and 2005, EOG had $733 million and $985 million, respectively, of long-term debt (including current portion), which had fair values of approximately $754 million and $1,025 million, respectively. The fair value of long-term debt is the value EOG would have to pay to retire the debt, including any premium or discount to the debt-holder for the differential between the stated interest rate and the year-end market rate. The fair value of long-term debt is based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at year-end.

3. Shareholders' Equity

Common Stock.

EOG purchases its common stock from time to time in the open market to be held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock plans and any other approved transactions or activities for which such common stock shall be required. In September 2001, the Board authorized the purchase of an aggregate maximum of 10 million shares of common stock of EOG which superseded all previous authorizations. At December 31, 2006, 6,386,200 shares remain available for repurchases under this authorization. On February 2, 2005, EOG announced that the Board had approved a two-for-one stock split in the form of a stock dividend, payable to record holders as of February 15, 2005 and issued on March 1, 2005. In addition, the Board increased the quarterly cash dividend on the common stock to a quarterly cash dividend of $0.04 per share post-split. On February 1, 2006, the Board increased the quarterly cash dividend on the common stock to $0.06 per share. On January 31, 2007, the Board increased the quarterly cash dividend on the common stock to $0.09 per share.

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

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2003	249,460	(17,639)	231,821
Treasury Stock Purchased	-	(320)	(320)
Treasury Stock Issued Under Stock Option Plans	-	5,922	5,922
Treasury Stock Issued Under Employee Stock Purchase Plan	-	136	136
Restricted Stock and Units	-	296	296
Balance at December 31, 2004	249,460	(11,605)	237,855
Treasury Stock Purchased	-	(155)	(155)
Treasury Stock Issued Under Stock Option Plans	-	3,804	3,804
Treasury Stock Issued	-	106	106

Under Employee Stock Purchase Plan			
Restricted Stock and Units	-	464	464
Balance at December 31, 2005	249,460	(7,386)	242,074
Treasury Stock Purchased	-	(265)	(265)
Treasury Stock Issued Under Stock Option Plans	-	1,368	1,368
Treasury Stock Issued Under Employee Stock Purchase Plan	-	92	92
Restricted Stock and Units	-	466	466
Balance at December 31, 2006	249,460	(5,725)	243,735

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

The Rights will not be exercisable until ten days after a public announcement that a person or group has become an acquiring person (Acquiring Person) by obtaining beneficial ownership of 10% or more of EOG's common stock, or if earlier, ten business days (or a later date determined by EOG's Board before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if consummated, would result in that person or group becoming an Acquiring Person. On February 24, 2005, the Rights Agreement was amended to create an exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 20% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the following requirements: (i) the institutional investor is described in Rule 13d-1(b)(1) promulgated under the Securities Exchange Act of 1934 and is eligible to report (and, if such institutional investor is the beneficial owner of greater than 5% of EOG's common stock, does in fact report) beneficial ownership of common stock on Schedule 13G; (ii) the institutional investor is not required to file a Schedule 13D (or any successor or comparable report) with respect to its beneficial ownership of EOG's common stock; (iii) the institutional investor does not beneficially own 15% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates other than those which, under published interpretations of the United States Securities and Exchange Commission or its staff, are eligible to file separate reports on Schedule 13G with respect to their beneficial ownership of EOG's common stock); and (iv) the institutional investor does not beneficially own 20% or more of EOG's common stock (including in such calculation the holdings of all of the institutional investor's affiliates and associates). On June 15, 2005, the Rights Agreement was amended again to revise the exception to the definition of Acquiring Person to permit a qualified institutional investor to hold 10% or more but less than 30% of EOG's common stock without being deemed an Acquiring Person if the institutional investor meets the other requirements of the definition of qualified institutional investor described in the amendment.

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

EOG's Board may redeem the Rights for $0.005 per Right at any time before any person or group becomes an Acquiring Person. If the Board redeems any Rights, it must redeem all of the Rights. Once the Rights are redeemed, the only right of the holders of Rights will be to receive the redemption price of $0.005 per Right. The redemption price has been adjusted for the two-for-one stock split effective March 1, 2005 and will be adjusted for any future stock split or stock dividends of EOG's common stock. After a person or group becomes an Acquiring Person, but before an Acquiring Person owns 50% or more of EOG's outstanding common stock, the Board may exchange the Rights for common stock or equivalent security at an exchange ratio of one share of common stock or an equivalent security for each such Right, other than Rights held by the Acquiring Person.

Preferred Stock.

EOG currently has two authorized series of preferred stock. On February 14, 2000, EOG's Board, in connection with the Rights Agreement described above, authorized 1,500,000 shares of the Series E with the rights and preferences described above. On February 24, 2005, EOG's Board increased the authorized shares of the Series

E to 3,000,000 as a result of the two-for-one stock split of EOG's common stock effective March 1, 2005. Currently, there are no shares of the Series E outstanding.

On July 19, 2000, EOG's Board authorized 100,000 shares of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 Liquidation Preference per share (Series B). Dividends are payable on the shares only if declared by EOG's Board and will be cumulative. If declared, dividends will be payable at a rate of $71.95 per share, per year on March 15, June 15, September 15 and December 15 of each year beginning September 15, 2000. EOG may redeem all or part of the Series B at any time beginning on December 15, 2009 at $1,000 per share, plus accrued and unpaid dividends. The Series B is not convertible into, or exchangeable for, common stock of EOG. On October 11, 2006, EOG commenced a cash tender offer to purchase any and all of the 100,000 outstanding shares of the Series B at a price of $1,074.01 per share plus accrued and unpaid dividends up to the date of purchase. The tender offer expired on November 8, 2006, and on November 10, 2006, EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including redemption premium, fees and dividends of $51 million. In accordance with the provisions of EITF Topic D-42, EOG has included as a component of preferred dividends the $4 million of premium and fees associated with the redemption of the Series B shares. A total of 53,260 shares of the Series B remain outstanding at December 31, 2006.

Following the December 2004 redemption of all outstanding shares of EOG's Flexible Money Market Cumulative Preferred Stock, Series D, EOG filed a Certificate of Elimination with the Secretary of State of the State of Delaware on February 24, 2005 to eliminate the series from EOG's Restated Certificate of Incorporation, as amended.

4. Other Income, Net

Other income, net for 2006 included interest income ($27 million), equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants ($18 million), net gains on sales of properties ($8 million) and settlements received related to the Enron Corp. bankruptcy ($4 million). Other income, net for 2005 included equity income from investments in CNCL and N2000 ammonia plants ($16 million), gains on sales of properties ($13 million), interest income ($8 million), a gain on the sale of part of EOG's interest in the N2000 ammonia plant ($2 million) and net foreign currency transaction losses ($2 million).

5. Income Taxes

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

	2006	2005
Current Deferred Income Tax (Assets) Liabilities		
Commodity Hedging Contracts	$ 50,786	$ 7,995
Deferred Compensation Plans	(9,501)	(7,366)
Net Operating Loss Carryforward (Current	-	(7,592)

Portion)		
Timing Differences Associated With Different Year-ends in Foreign Jurisdictions	121,677	164,659
Other	(18,347)	(17,413)
Total Net Current Deferred Income Tax Liability	$ 144,615	$ 140,283
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$1,658,124	$1,226,433
Non-Producing Leasehold Costs	(59,862)	(51,130)
Seismic Costs Capitalized for Tax	(53,777)	(41,328)
Equity Awards	(11,688)	-
Capitalized Interest	26,957	21,332
Other	(46,626)	(32,719)
Total Net Noncurrent Deferred Income Tax Liability	$1,513,128	$1,122,588
Total Net Deferred Income Tax Liability	$1,657,743	$1,262,871

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The components of Income Before Income Taxes for the years indicated below were as follows (in thousands):

	2006	2005	2004
United States	$ 1,343,669	$ 1,336,658	$ 641,973
Foreign	568,972	628,479	284,039
Total	$ 1,912,641	$ 1,965,137	$ 926,012

The principal components of EOG's Income Tax Provision for the years indicated below were as follows (in thousands):

	2006	2005	2004
Current:			
Federal	$ 78,910	$ 333,752	$ 58,148
State	1,050	25,527	3,137
Foreign	146,954	75,991	35,641
Total	226,914	435,270	96,926
Deferred:			
Federal	377,543	132,118	156,862
State	11,475	14,774	7,985
Foreign	(3,176)	123,399	39,384
Total	385,842	270,291	204,231
Income Tax Provision	$ 612,756	$ 705,561	$ 301,157

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

	2006	2005	2004
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	0.15	1.32	0.74
Income Tax Provision Related	(0.10)	(0.92)	(1.83)

to Foreign Operations			
Change in Canadian Federal and Provincial Statutory Tax Rates and Other	(3.18)	-	(0.58)
Canadian Adjustments			
Change in United Kingdom Tax Rates	0.38	-	-
Change in Texas Tax Rates	0.27	-	-
Dividend Repatriation	-	1.20	-
Domestic Production Activities Deduction	(0.06)	(0.42)	-
Other	(0.42)	(0.28)	(0.81)
Effective Income Tax Rate	32.04%	35.90%	32.52%

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was enacted. The Act created a temporary incentive for United States corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. During the fourth quarter of 2005, EOG made a qualifying distribution in the amount of $450 million resulting in a federal income tax of approximately $24 million.

EOG's foreign subsidiaries' undistributed earnings of approximately $1.8 billion at December 31, 2006 are considered to be indefinitely invested outside the United States and, accordingly, no United States or state income taxes have been provided thereon. Upon distribution of those earnings, EOG may be subject to both foreign withholding taxes and United States income taxes, net of allowable foreign tax credits. Determination of any potential amount of unrecognized deferred income tax liabilities is not practicable.

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

Through 2004, EOG incurred foreign net operating losses of approximately $70 million, of which $51 million was utilized in 2005. The remaining $19 million net operating loss was utilized in 2006.

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

6. Employee Benefit Plans

Pension Plans and Postretirement Benefits

At December 31, 2006, EOG and its subsidiaries in Canada and Trinidad maintained certain defined benefit pension and postretirement medical plans covering certain eligible employees. EOG adopted the provisions of SFAS No. 158 applicable to 2006 during the fourth quarter of 2006 and recognized the funded status of the defined benefit plans as of December 31, 2006. The impact of SFAS No. 158 was to recognize a non-current asset of $0.1 million, current liability of $0.1 million, a non-current liability of $0.8 million and related deferred income taxes of $0.3 million, with an offsetting charge to accumulated other comprehensive income of $0.5 million representing previously unrecognized prior service costs and actuarial gains and losses associated with the defined benefit plans. During 2007, approximately $0.2 million of such costs will be amortized from accumulated other comprehensive income through net periodic benefit costs.

Pension Plan.

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. EOG's contributions to these pension plans are based on various percentages of compensation, and in some instances, are based upon the amount of the employees' contributions. EOG's total contributions to these pension plans amounted to $14 million, $12 million and $11 million for 2006, 2005 and 2004, respectively.

In addition, EOG's Canadian subsidiary maintains both a non-contributory defined benefit pension plan and a non-contributory defined contribution pension plan, as well as a matched defined contribution savings plan. EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. With the exception of Canada's contributory defined benefit pension plan, which is closed to new employees, these pension plans are available to most employees of the Canadian and Trinidadian subsidiaries. EOG's combined contributions to these pension plans were $2.1 million, $2.0 million and $0.9 million for 2006, 2005 and 2004, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and accrued benefit cost totaled $6.7 million, $6.0 million and $0.7 million, respectively, at December 31, 2006 and $6.4 million, $5.3 million and $1.1 million, respectively, at December 31, 2005. Weighted average discount rate and expected return on plan assets assumptions used to determine benefit obligations for the pension plans were 5.75% and 7.10% respectively, at December 31, 2006 and 5.54% and 6.57%, respectively, at December 31, 2005. Weighted average discount rate assumptions used to determine net periodic benefit cost for the pension plans for the years ended December 31, 2006, 2005 and 2004 were 5.98%, 6.50% and 6.50%, respectively. The weighted average asset allocation of the pension plans at December 31, 2006 consisted of equities (55%), debt and fixed income securities (40%) and other assets (5%). The asset allocation at December 31, 2005 consisted of equities (57%), debt and fixed income securities (38%) and other (5%).

The investment policy for the defined benefit pension plan in Trinidad is determined by the pension plan's trustee, with input from EOG. The plan's asset allocation policy is largely dictated by local statutory requirements which restricts total investment in equities to a maximum of 50% of the plan's assets and investment overseas to 20% of the plan's assets. The investment policy for the defined benefit pension plan in Canada provides that EOG shall invest the plan assets in one or more balanced funds with Canadian and foreign equity components as deemed appropriate for the purpose of diversification.

EOG's United Kingdom subsidiary introduced a pension plan as of January 2005, which includes a non-contributory defined contribution pension plan and a matched defined contribution savings plan. The pension plan is available to all employees of the United Kingdom subsidiary. EOG's combined contributions to these pension plans were approximately $0.1 million for both 2006 and 2005.

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Postretirement Health Care. EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents. EOG accrues these postretirement benefit costs over the service lives of the employees expected to be eligible to receive such benefits.

The benefit obligation and accrued benefit cost for the postretirement benefit plans totaled $3.7 million each at December 31, 2006 and $3.4 million and $2.0 million, respectively, at December 31, 2005. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2006 and 2005 were 5.95% and 5.67%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2006, 2005 and 2004 were 5.68%, 5.98% and 6.15%, respectively. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.7 million, $0.4 million and $0.5 million for the years ended December 31, 2006, 2005 and 2004.

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

	Pension Plans	Postretirement Plans
2007	$ 232	$ 134
2008	231	147
2009	252	187
2010	252	210
2011	302	243
2012 - 2016	1,885	1,890

Postretirement health care trend rates had minimal effect on the amounts reported for the postretirement health care plans for both 2006 and 2005. Most future increases or decreases in healthcare costs would be borne by the employee.

Stock-Based Compensation

At December 31, 2006, EOG maintained various stock-based compensation plans as discussed below. EOG adopted SFAS No. 123(R) effective January 1, 2006 using the modified prospective application method and accordingly has not restated any of its prior year results. Prior to the adoption of SFAS 123(R), EOG recognized compensation expense for its stock-based compensation plans under the provisions of APB Opinion No. 25 as allowed by SFAS No. 123 "Accounting for Stock-Based Compensation." Stock-based compensation expense prior to January 1, 2006 consisted of amounts recognized in connection with grants of restricted stock and units. The adoption of SFAS No. 123(R) resulted in EOG recognizing compensation expense on grants of stock options, Stock-Settled Stock Appreciation Rights (SARs) and grants made under its employee stock purchase plan (ESPP). Stock-based compensation expense for the year ended December 31, 2006 included expense for all stock-based compensation awards that were not yet vested as of January 1, 2006 and all such awards granted after January 1, 2006 based upon the grant date estimated fair value of the awards. Such expense is computed net of forfeitures estimated based upon EOG's historical employee turnover rate. For awards made prior to January 1, 2006, compensation expense is amortized over the vesting period on a straight-line basis. For awards made subsequent to January 1, 2006, compensation expense is amortized over the shorter of the vesting period or the period from date of grant until the date the employee becomes eligible to retire without company approval.

Stock-based compensation expense for periods subsequent to January 1, 2006 is included in the Consolidated Statements of Income based upon job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years 2006, 2005 and 2004 was as follows (in millions):

	2006	**2005**	**2004**
Lease and Well	$ 10	$ -	$ -
Exploration Costs	11	-	-
General and Administrative	29	12	10
Total (1)	$ 50	$ 12	$ 10

(1) The 2006 amount includes $1 million of expense related to stock-based compensation awards issued to retirement-eligible
employees prior to January 1, 2006, which is being amortized over the vesting period on a straight-line basis.

The impact of SFAS No. 123(R) was to reduce income before income taxes and net income during the year ended December 31, 2006 by $28.7 million and $18.5 million, respectively, and to reduce both basic and diluted net income per share available to common by $0.08. EOG's pro forma net income and net income per share available to common for 2005 and 2004 had compensation costs been recorded in accordance with SFAS No. 123, are presented below (in millions, except per share data):

	2005	J004
Net Income Available to Common - As Reported	$ 1,252.1	$ 614.0
Deduct: Total Stock-Based Employee Compensation Expense, Net of Income Tax	(13.7)	(11.9)
Net Income	$ 1,238.4	$ 602.1

Available to Common - Pro Forma

Net Income Per Share Available to Common				
Basic - As Reported	$	5.24	$	2.63
Basic - Pro Forma	$	5.19	$	2.58
Diluted - As Reported	$	5.13	$	2.58
Diluted - Pro Forma	$	5.08	$	2.53

EOG has various stock plans (Plans) under which employees and non-employee members of the Board of Directors of EOG and its subsidiaries have been or may be granted certain equity compensation. Since the inception of the Plans, there have been 62,890,000 shares authorized for grant. At December 31, 2006, 3,233,165 shares remain available for grant.

Stock Options and Stock Appreciation Rights.

Under the Plans, participants have been or may be granted options to purchase shares of common stock of EOG at a price not less than the market price of the stock on the date of grant. In September 2006, EOG began granting SARs to the participants of the Plans. Each SAR represents the right to receive shares of EOG common stock based on the appreciation in the stock price from the date of grant on the number of shares granted. Stock options and SARs granted under the Plans vest on a graded vesting schedule up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options and SARs granted under the Plans have not exceeded a maximum term of 10 years. For all grants made prior to August 2004 and all ESPP grants, the fair value of each grant was estimated using the Black-Scholes-Merton model. Certain of EOG's stock options granted in 2005 and 2004 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not issue Capped Options in the future. The fair value of each Capped Option grant was estimated using a Monte Carlo simulation. Effective May 2005, the fair value of stock option grants not containing the Capped Option feature and the fair value of SARs was estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock options, SARs and ESPP grants totaled $34.8 million for the year ended December 31, 2006.

Weighted average fair values and valuation assumptions used to value stock options, SARs and ESPP grants for the years 2006, 2005 and 2004 were as follows:

Stock Options/SARs			ESPP		
2006	2005	2004	2006	2005	2004

Weighted Average Fair Value of Grants	$22.56	$19.82	$21.53	$20.32	$ 9.81	$12.01
Expected Volatility	34.22%	31.92%	31.79%	41.09%	30.32%	26.23%
Risk-Free Interest Rate	4.96%	4.15%	4.10%	4.89%	2.98%	1.93%
Dividend Yield	0.30%	0.36%	0.40%	0.30%	0.38%	0.40%
Expected Life	5.1 yrs	5.0 yrs	4.8 yrs	0.5 yrs	0.5 yrs	0.5 yrs

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock options, SARs and ESPP grants.

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

	2006		2005		2004	
	Options/ SARs	Weighted Average Grant Price	Options	Weighted Average Grant Price	Options	Weighted Average Grant Price
Outstanding at January 1	9,698	$28.26	11,922	$19.78	15,497	$15.29
Granted	2,038	62.25	1,823	61.57	2,619	31.97
Exercised [(1)]	(1,368)	23.80	(3,804)	17.61	(5,922)	13.43
Forfeited	(218)	42.03	(243)	28.86	(272)	19.34
Outstanding at December 31	10,150	35.29	9,698	28.26	11,922	19.78
Options/SARs Exercisable at December 31	5,325	20.91	4,575	16.61	6,104	15.18
Available for Future Grant	3,233		5,606		7,418	

(1) The total intrinsic value of stock options exercised during the years 2006, 2005 and 2004 was $65.0 million, $154.5 million and $92.0 million,
respectively. The intrinsic value is based upon the difference between the market price of EOG common stock on the date of exercise and the

grant price of the stock options.

At December 31, 2006, there are 9,608,721 stock options/SARs vested or expected to vest with a weighted average grant price of $35.18, an intrinsic value of $265 million and a weighted average remaining contractual life of 5.8 years.

At December 31, 2006, unrecognized compensation expense related to non-vested stock options, SARs and ESPP grants totaled $78.1 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.1 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2006 (stock options and SARs in thousands):

	Options/SARs Outstanding				Options/SARs Exercisable			
Range of Grant Prices	Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value [(1)]	Options	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value [(1)]
$ 7.00 to $16.99	1,685	4	$14.04		1,685	4	$14.04	
17.00 to 19.99	2,397	5	18.18		2,224	5	18.07	
20.00 to 31.99	1,334	6	21.40		989	6	21.47	
32.00 to 48.99	1,157	8	33.67		40	8	47.40	
49.00 to 82.99	3,577	6	62.47		387	6	62.87	
	10,150	6	35.29	$278,920	5,325	5	20.91	$221,515

(1) Based upon the difference between the closing market price of EOG common stock on the last trading day of the year and the grant
price of in-the-money stock options and SARs.

Restricted Stock and Units.

Under the Plans, employees may be granted restricted (non-vested) stock and/or units without cost to them. The restricted stock and units granted vest to the employee at various times ranging from one to five years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Upon vesting, restricted stock is released to the employee and restricted units are converted into common stock and released to the employee. Stock-based compensation expense related to restricted stock and units totaled $15 million, $12 million and $10 million for the years ended December 31, 2006, 2005 and 2004, respectively.

The following table sets forth the restricted stock and units transactions for the year 2006 (shares, units and dollars in thousands, except per share data):

	2006		2005		2004	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	2,544	$26.04	2,566	$19.90	2,052	$17.77
Granted	542	64.29	385	52.19	659	25.75

Released [1]	(702)	20.74	(353)	9.57	(82)	15.01
Forfeited	(83)	41.50	(54)	27.91	(63)	18.00
Outstanding at December 31 [2]	2,301	36.13	2,544	26.04	2,566	19.90

(1) The total intrinsic value of restricted stock and units released during the years ended December 31, 2006, 2005 and 2004 was $50.3 million, $14.6 million and $2.5 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and units are released.
(2) The aggregate intrinsic value of restricted stock and units outstanding at December 31, 2006 was approximately $143.7 million.

At December 31, 2006, unrecognized compensation expense related to restricted stock and units totaled $54.8 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.4 years.

Employee Stock Purchase Plan

. EOG has an ESPP in place that allows eligible employees to semi-annually purchase, through payroll deductions, shares of EOG common stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employees' pay (subject to certain ESPP limits) during each of the two six-month offering periods. As of December 31, 2006, approximately 315,800 common shares remained available for issuance under the ESPP.

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

	2006	2005	2004
Approximate Number of Participants	730	580	450
Shares Purchased	92	106	136
Aggregate Purchase Price	$5,110	$3,889	$3,021

During 2006, 2005 and 2004, EOG issued treasury shares in connection with stock option exercises, restricted stock grants, restricted unit releases and ESPP purchases. The difference between the cost of the treasury shares and the exercise price of the options is reflected as an adjustment to additional paid in capital to the extent EOG has accumulated additional paid in capital relating to treasury stock and to retained earnings thereafter. Additionally, EOG recognized as an adjustment to additional paid in capital, federal income tax benefits of $31 million, $51 million and $29 million for 2006, 2005 and 2004, respectively, related to the exercise of stock options and the release of restricted stock and units.

7. Commitments and Contingencies

Letters of Credit.

At December 31, 2006, EOG had standby letters of credit and guarantees outstanding totaling approximately $630 million of which $505 million represents guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt" and $125 million primarily represents guarantees of payment obligations on behalf of subsidiaries. At December 31, 2005, EOG had standby letters of credit and guarantees outstanding totaling approximately $711 million of which $620 million represents guarantees of subsidiary indebtedness and $91 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 26, 2007, there were no demands for payment under these guarantees.

Minimum Commitments.

At December 31, 2006, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase and other purchase obligations, and pipeline transportation service commitments, based on current pipeline transportation rates and the foreign currency exchange rates used to convert Canadian Dollars and British Pounds into United States Dollars at December 31, 2006, are as follows (in thousands):

	Total Minimum Commitments
2007	$ 363,861
2008 - 2010	770,807
2011 - 2012	374,021
2013 and beyond	867,169
	$ 2,375,858

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2022. Rental expenses associated with existing leases amounted to $46 million, $34 million and $26 million for 2006, 2005 and 2004, respectively.

Contingencies.

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

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8. Net Income Per Share Available to Common

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

	2006	2005	2004
Numerator for basic and diluted earnings per share -			
Net Income	$1,299,885	$1,259,576	$624,855
Less: Preferred Stock Dividends	10,995	7,432	10,892
	$1,288,890	$1,252,144	$613,963

Net Income Available to Common			
Denominator for basic earnings per share -			
Weighted average shares	241,782	238,797	233,751
Potential dilutive common shares -			
Stock options	3,261	3,942	3,561
Restricted stock and units	1,057	1,236	1,064
Denominator for diluted earnings per share -			
Adjusted weighted average shares	246,100	243,975	238,376
Net Income Per Share Available to Common			
Basic	$ 5.33	$ 5.24	$ 2.63
Diluted	$ 5.24	$ 5.13	$ 2.58

The diluted earnings per share calculation excludes 0.1 million, 1.0 million and 0.5 million of SARs and stock options that were anti-dilutive for the years ended December 31, 2006, 2005, and 2004, respectively.

On November 10, 2006, EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including premium, fees and dividends of $51 million. See Note 3.

9. Supplemental Cash Flow Information

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

	2006	2005	2004
Interest	$ 41,174	$ 60,467	$ 60,967
Income taxes	301,214	335,628	56,654

10. Business Segment Information

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

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

	United States	Canada	Trinidad	United Kingdom	Other	Total
2006						
Natural Gas	$1,955,458	$ 529,294	$ 234,741	$ 83,752	$ -	$2,803,245
Crude Oil, Condensate and Natural Gas Liquids	583,579	64,383	110,936	2,682	-	761,580
Gains on Mark-to-Market Commodity Derivative Contracts	334,260	-	-	-	-	334,260
Other, Net	4,861	(3)	11	461	-	5,330
Net Operating Revenues [(1)]	2,878,158	593,674	345,688	86,895	-	3,904,415
Depreciation, Depletion and Amortization	623,311	143,368	26,623	23,787	-	817,089
Operating Income	1,320,673	277,009	250,470	47,799	(525)	1,895,426
Interest Income	17,159	4,861	4,697	-	-	26,717
Other Income (Expense)	16,414	(6,412)	18,925	4,724	5	33,656
Interest Expense, Net	11,597	21,531	9,988	42	-	43,158
Income Before Income Taxes	1,342,649	253,927	264,104	52,481	(520)	1,912,641
	463,948	13,286	107,648	27,874	-	612,756

Income Tax Provision						
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	2,175,974	416,834	117,668	29,187	-	2,739,663
Net Oil and Gas Properties	5,503,028	2,009,637	371,064	60,318	-	7,944,047
Total Assets	6,523,148	2,146,846	636,885	95,220	61	9,402,160
2005						
Natural Gas	$2,058,361	$ 594,689	$ 185,954	$ 99,913	$ -	$2,938,917
Crude Oil, Condensate and Natural Gas Liquids	512,830	56,660	94,668	3,915	-	668,073
Gains on Mark-to-Market Commodity Derivative Contracts	10,475	-	-	-	-	10,475
Other, Net	2,351	(1)	-	398	-	2,748
Net Operating Revenues [(2)]	2,584,017	651,348	280,622	104,226	-	3,620,213
Depreciation, Depletion and Amortization	488,621	124,793	24,781	16,063	-	654,258
Operating Income	1,356,267	377,580	204,133	53,835	-	1,991,815
Interest Income	1,218	2,139	4,510	-	-	7,867
Other Income (Expense)	19,351	(5,029)	17,631	(3,992)	-	27,961
Interest Expense, Net	38,683	22,843	909	71	-	62,506
Income Before Income Taxes	1,338,153	351,847	225,365	49,772	-	1,965,137
Income Tax Provision	485,523	110,794	88,919	20,325	-	705,561
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	1,299,205	307,862	42,384	10,500	-	1,659,951
Net Oil and Gas Properties	4,009,700	1,757,123	277,113	43,243	-	6,087,179
Total Assets	5,176,701	1,958,655	538,671	79,293	-	7,753,320

	United States	Canada	Trinidad	United Kingdom	Other	Total
2004						
Natural Gas	$1,322,838	$ 404,023	$ 102,890	$ 12,565	$ -	$1,842,316
Crude Oil, Condensate and Natural Gas Liquids	363,229	44,334	50,487	396	-	458,446
(Losses) on Mark-to-Market Commodity Derivative Contracts	(33,449)	-	-	-	-	(33,449)
Other, Net	3,707	205	-	-	-	3,912
Net Operating Revenues (3)	1,656,325	448,562	153,377	12,961	-	2,271,225
Depreciation, Depletion and Amortization	382,718	99,879	20,022	1,784	-	504,403
Operating Income (Loss)	682,619	222,155	91,245	(16,824)	-	979,195
Interest Income	292	679	659	-	-	1,630
Other Income (Expense)	1,072	(4,487)	10,892	838	-	8,315
Interest Expense, Net	41,571	21,415	-	142	-	63,128
Income (Loss) Before Income Taxes	642,412	196,932	102,796	(16,128)	-	926,012
Income Tax Provision (Benefit)	231,250	45,785	31,414	(7,292)	-	301,157
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	936,463	294,571	59,205	34,303	-	1,324,542
Net Oil and Gas Properties	3,276,718	1,515,414	256,858	52,613	-	5,101,603
Total Assets	3,727,231	1,600,486	401,434	69,772	-	5,798,923

(1) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2006 that totaled $397 million of consolidated Net Operating Revenues.

(2) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2005 that

totaled $385 million of consolidated Net Operating Revenues.
(3) EOG had sales activity with a single significant purchaser in the United States and Canada segments in 2004 that totaled $280 million of consolidated Net Operating Revenues.

11. Price, Interest Rate and Credit Risk Management Activities

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

During 2006, 2005 and 2004, EOG elected not to designate any of its financial commodity derivative contracts as accounting hedges and accordingly, accounted for these financial commodity derivative contracts using the mark-to-market accounting method. During 2006, EOG recognized gains on mark-to-market financial commodity derivative contracts of $334 million, which included realized gains of $215 million. During 2005, EOG recognized gains on mark-to-market financial commodity derivative contracts of $10 million, which included realized gains of $10 million. During 2004, EOG recognized losses on mark-to-market financial commodity derivative contracts of $33 million, which included realized losses of $82 million and collar premium payments of $1 million.

Presented below is a comprehensive summary of EOG's 2007 natural gas and crude oil financial price swap contracts at December 31, 2006 with prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), as applicable, and notional volumes in million British thermal units per day (MMBtud) and in barrels per day (Bbld), as applicable. Currently, EOG is not a party to any financial collar contracts. The total fair value of the natural gas and crude oil financial price swap contracts at December 31, 2006 was $131 million.

Financial Price Swap Contracts

	Natural Gas		Crude Oil	
Month	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
January (closed)	120,000	$10.91	4,000	$78.42
February (1)	120,000	10.93	4,000	78.55
March	120,000	10.75	4,000	78.58
April	120,000	8.81	4,000	78.57
May	120,000	8.65	4,000	78.50
June	120,000	8.74	4,000	78.40
July	120,000	8.84	4,000	78.28
August	120,000	8.92	4,000	78.16
September	120,000	9.00	4,000	78.03
October	120,000	9.14	4,000	77.91
November	120,000	9.94	4,000	77.75

December	120,000	10.70	4,000	77.57

(1) The natural gas contracts for February 2007 are closed. The crude oil contracts for February 2007 will close on February 28, 2007.

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

	2006		2005	
	Carrying Amount	Estimated Fair Value (1)	Carrying Amount	Estimated Fair Value (1)
Current and Long-Term Debt (2)	$ 733	$ 754	$ 985	$ 1,025
NYMEX-Related Commodity Market Positions	131	131	11	11
Foreign Currency Swap Liability	36	36	36	36

(1) Estimated fair values have been determined by using available market data and valuation methodologies. Judgment is required in interpreting market data and the use of different market assumptions or estimation methodologies may affect the estimated fair value amounts.
(2) See Note 2.

Credit Risk.

While notional contract amounts are used to express the magnitude of commodity price and foreign currency swap agreements, the amounts potentially subject to credit risk, in the event of nonperformance by the other parties, are substantially smaller. EOG evaluates its exposure to all counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk. At December 31, 2006, EOG's net accounts receivable balance related to Unites States and Canada hydrocarbon sales included one receivable balance which constituted 12% of the total balance. This receivable was due from an integrated oil and gas company. The related amount was collected in January 2007. At December 31, 2005, no individual purchaser's accounts receivable balance related to United States and Canada hydrocarbon sales accounted for 10% or more of the total balance. In 2006 and 2005, natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago.

At December 31, 2006, EOG had an allowance for doubtful accounts of $17 million, of which $15 million is associated with the Enron Corp. bankruptcies recorded in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2006 and 2005 resulted from hydrocarbon sales and/or joint interest billings to third party companies including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer or joint interest owner, EOG analyzes the entity's net worth, cash flows, earnings, and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2006, credit losses incurred on receivables by EOG have been immaterial.

12. Accounting for Certain Long-Lived Assets

EOG reviews its oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. During 2006, 2005 and 2004, such reviews indicated that unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows due primarily to downward reserve revisions, drilling of marginal or uneconomic wells, or development dry holes in certain producing fields. As a result, EOG recorded pretax charges of $48 million, $31 million and $17 million in the United States operating segment during 2006, 2005 and 2004, respectively, and $7 million and $8 million in the Canada operating segment during 2006 and 2004, respectively. There were no pretax charges recorded in the Canada operating segment in 2005. The pretax charges are included in Impairments on the Consolidated Statements of Income and Comprehensive Income. The carrying values for assets determined to be impaired were adjusted to estimated fair values based on projected future net cash flows discounted using EOG's risk-adjusted discount rate. Amortization expenses of lease acquisition costs of unproved properties, including amortization of capitalized interest, were $53 million, $47 million and $57 million for 2006, 2005 and 2004, respectively.

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13. Accounting for Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of legal obligations associated with the retirement of oil and gas properties pursuant to SFAS No. 143 (in thousands):

	2006	2005
Carrying Amount at Beginning of Period	$161,488	$138,759
Liabilities Incurred	19,921	8,449
Liabilities Settled	(8,499)	(5,965)
Accretion	8,537	7,682
Revisions	(53)	9,513
Foreign Currency Translations	1,012	3,050
Carrying Amount at End of Period	$182,406	$161,488
Current Portion	$ 9,507	$ 6,235
Noncurrent Portion	$172,899	$155,253

14. Investment in Caribbean Nitrogen Company Limited and Nitrogen (2000) Unlimited

EOG, through certain wholly-owned subsidiaries, owns equity interests in two Trinidadian companies: CNCL and N2000. During the first quarters of 2005 and 2004, EOG completed separate share sale agreements whereby portions of the EOG subsidiaries' shareholdings in CNCL and N2000 were sold to a third party energy company. The 2005 N2000 sale resulted in a pretax gain of $2 million. The 2004 sale did not result in any gain or loss. At December 31, 2006, EOG's equity interests in CNCL and N2000 were 12% and 10%, respectively.

At December 31, 2006, the investment in CNCL was $19 million. CNCL commenced ammonia production in June 2002. At December 31, 2006, CNCL had a long-term debt balance of $142 million, which is non-recourse to CNCL's shareholders. EOG will be liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of CNCL up to $30 million, approximately $4 million of which is net to EOG's interest. The shareholders' agreement governing CNCL requires the consent of the holders of 90% or more of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of CNCL and therefore, it accounts for the investment using the equity method. During 2006, EOG recognized equity income of $8 million and received cash dividends of $7

million from CNCL.

At December 31, 2006, the investment in N2000 was $17 million. N2000 commenced ammonia production in August 2004. At December 31, 2006, N2000 had a long-term debt balance of $166 million, which is non-recourse to N2000's shareholders. At December 31, 2006, EOG was liable for its share of any post-completion deficiency funds, loans to fund the costs of operation, payment of principal and interest to the principal creditor and other cash deficiencies of N2000 up to $30 million, approximately $3 million of which is net to EOG's interest. The shareholders' agreement governing N2000 requires the consent of the holders of 100% of the shares to take certain material actions. Accordingly, given its current level of equity ownership, EOG is able to exercise significant influence over the operating and financial policies of N2000 and therefore, it accounts for the investment using the equity method. During 2006, EOG recognized equity income of $10 million and received cash dividends of $9 million

from N2000.

15. Suspended Well Costs

EOG's net changes in suspended well costs for the years ended December 31, 2006, 2005 and 2004, in accordance with FSP No. 19-1, "Accounting for Suspended Well Costs," are presented below (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Balance at January 1	$ 27,868	$20,520	$14,964
Additions Pending the Determination of Proved Reserves	64,449	18,533	15,634
Reclassifications to Proved	(10,474)	(9,245)	(6,206)

Properties Charged to Dry Hole Costs	(3,901)	(2,267)	(4,295)
Foreign Currency Translation	(577)	327	423
Balance at December 31	$ 77,365	$27,868	$20,520

The following table provides an aging of suspended well costs for the years ended December 31, 2006, 2005 and 2004 (in thousands, except well count):

	Year Ended December 31,		
	2006	2005	2004
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 50,589	$14,878	$16,270
Capitalized exploratory well costs that have been capitalized for a period greater than one year	26,776 (1)	12,990 (2)	4,250 (3)
Total	$ 77,365	$27,868	$20,520
Number of exploratory wells that have been capitalized for a period greater than one year	2	2	1

(1) Costs related to an outside operated, deepwater offshore Gulf of Mexico discovery ($4 million) and an outside operated, winter access only,

Northwest Territories (NWT) discovery in Northern Canada ($23 million). In the Gulf of Mexico project, EOG is currently participating in the drilling of an additional well. In the NWT project, EOG interpreted seismic data and identified potential drilling locations for the 2007 and 2008 winter drilling season.

(2) Costs related to the deepwater offshore Gulf of Mexico discovery ($4 million) and the winter access only NWT discovery ($9 million).

(3) Costs related to the deepwater offshore Gulf of Mexico discovery.

Oil and Gas Producing Activities

The following disclosures are made in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves.

Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

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

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

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

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

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EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimates of proved and proved developed reserves at December 31, 2006, 2005 and 2004 were based on studies performed by the engineering staff of EOG for all reserves. Opinions by DeGolyer and MacNaughton (D&M), independent petroleum consultants, for the years ended December 31, 2006, 2005 and 2004 covered producing areas containing 82%, 82% and 77%, respectively, of proved reserves of EOG on a net-equivalent-cubic-feet-of-gas basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's engineering staff for the properties reviewed by D&M, when compared in total on a net-equivalent-cubic-feet-of-gas basis, do not differ materially from the estimates prepared by D&M. Such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the engineering staff of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG.

No major discovery or other favorable or adverse event subsequent to December 31, 2006 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following tables set forth EOG's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 2006, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2006, as estimated by the engineering staff of EOG.

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Trinidad	United Kingdom	TOTAL
NET PROVED RESERVES					
Natural Gas (Bcf)					
(1)					
Net proved reserves at December 31, 2003	2,101.6	1,178.5	1,305.5	59.2	4,644.8
	(62.8)	(26.8)	34.2	-	(55.4)

Revisions of previous estimates					
Purchases in place	44.4	16.6	-	-	61.0
Extensions, discoveries and other additions	537.8	208.0	37.9	-	783.7
Sales in place	(1.3)	(0.6)	-	-	(1.9)
Production	(237.2)	(77.4)	(68.2)	(2.4)	(385.2)
Net proved reserves at December 31, 2004	2,382.5	1,298.3	1,309.4	56.8	5,047.0
Revisions of previous estimates	(21.3)	3.1	26.7	(22.6)	(14.1)
Purchases in place	30.2	-	-	-	30.2
Extensions, discoveries and other additions	835.9	104.7	-	15.0	955.6
Sales in place	(11.8)	-	-	-	(11.8)
Production	(267.4)	(83.3)	(84.5)	(14.3)	(449.5)
Net proved reserves at December 31, 2005	2,948.1	1,322.8	1,251.6	34.9	5,557.4
Revisions of previous estimates	(174.9)	(108.7)	(0.8)	(5.0)	(289.4)
Purchases in place	16.7	8.1	-	-	24.8
Extensions, discoveries and other additions	985.4	174.3	141.0	-	1,300.7
Sales in place	(0.6)	(4.3)	-	-	(4.9)
Production	(303.8)	(82.6)	(96.4)	(10.9)	(493.7)
Net proved reserves at December 31, 2006	3,470.9	1,309.6	1,295.4	19.0	6,094.9

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Canada	Trinidad	United Kingdom	TOTAL
Liquids (MBbl) (2)					
Net proved reserves at December 31, 2003	73,008	8,266	13,905	84	95,263
Revisions of previous estimates	2,649	(116)	3,417	69	6,019
Purchases in place	157	1	-	-	158
Extensions, discoveries and other additions	9,859	920	229	-	11,008
Sales in place	(411)	(14)	-	-	(425)
Production	(9,474)	(1,290)	(1,291)	(9)	(12,064)
Net proved reserves at December 31, 2004	75,788	7,767	16,260	144	99,959
Revisions of previous estimates	3,539	1,361	(1,444)	4	3,460
Purchases in place	1,340	-	-	-	1,340
Extensions, discoveries and other additions	14,021	915	-	68	15,004
Sales in place	(410)	-	-	-	(410)
Production	(10,234)	(1,219)	(1,651)	(79)	(13,183)
Net proved reserves at December 31, 2005	84,044	8,824	13,165	137	106,170

Revisions of previous estimates	5,835	774	75	(28)	6,656
Purchases in place	419	-	-	-	419
Extensions, discoveries and other additions	17,677	1,171	-	-	18,848
Sales in place	(677)	-	-	-	(677)
Production	(10,682)	(1,189)	(1,736)	(47)	(13,654)
Net proved reserves at December 31, 2006	96,616	9,580	11,504	62	117,762
Bcf Equivalent (Bcfe) [(1)]					
Net proved reserves at December 31, 2003	2,539.7	1,228.1	1,388.8	59.7	5,216.3
Revisions of previous estimates	(47.0)	(27.5)	54.8	0.4	(19.3)
Purchases in place	45.4	16.6	-	-	62.0
Extensions, discoveries and other additions	597.0	213.5	39.3	-	849.8
Sales in place	(3.8)	(0.7)	-	-	(4.5)
Production	(294.1)	(85.1)	(75.9)	(2.5)	(457.6)
Net proved reserves at December 31, 2004	2,837.2	1,344.9	1,407.0	57.6	5,646.7
Revisions of previous estimates	(0.1)	11.3	18.1	(22.6)	6.7
Purchases in place	38.2	-	-	-	38.2
Extensions, discoveries and other additions	920.0	110.2	-	15.4	1,045.6

Sales in place	(14.2)	-	-	-	(14.2)
Production	(328.7)	(90.7)	(94.4)	(14.8)	(528.6)
Net proved reserves at December 31, 2005	3,452.4	1,375.7	1,330.7	35.6	6,194.4
Revisions of previous estimates	(139.8)	(104.0)	(0.5)	(5.1)	(249.4)
Purchases in place	19.2	8.1	-	-	27.3
Extensions, discoveries and other additions	1,091.5	181.3	141.0	-	1,413.8
Sales in place	(4.7)	(4.3)	-	-	(9.0)
Production	(368.0)	(89.7)	(106.8)	(11.1)	(575.6)
Net proved reserves at December 31, 2006	4,050.6	1,367.1	1,364.4	19.4	6,801.5

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Canada	Trinidad	United Kingdom	TOTAL
<u>NET PROVED DEVELOPED RESERVES</u>					
Natural Gas (Bcf) [(1)]					
December 31, 2003	1,749.3	889.2	429.9	-	3,068.4
December 31, 2004	1,855.7	1,070.1	760.9	56.8	3,743.5
December 31, 2005	2,090.6	1,141.0	703.9	28.8	3,964.3
December 31, 2006	2,416.2	1,162.2	610.0	19.0	4,207.4
Liquids (MBbl) [(2)]					
December 31, 2003	56,321	7,995	5,229	-	69,545
December 31, 2004	60,478	7,414	10,874	144	78,910
December 31, 2005	69,887	8,651	7,799	110	86,447

December 31, 2006	79,555	9,427	6,119	62	95,163
Bcf Equivalents (Bcfe) (1)					
December 31, 2003	2,087.3	937.2	461.2	-	3,485.7
December 31, 2004	2,218.5	1,114.7	826.2	57.6	4,217.0
December 31, 2005	2,509.9	1,192.9	750.7	29.5	4,483.0
December 31, 2006	2,893.5	1,218.8	646.7	19.4	4,778.4

(1) Billion cubic feet or billion cubic feet equivalent, as applicable. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil, condensate or natural gas liquids.
(2) Thousand barrels; includes crude oil, condensate and natural gas liquids.

Capitalized Costs Relating to Oil and Gas Producing Activities.

The following table sets forth the capitalized costs relating to EOG's natural gas and crude oil producing activities at December 31 of the years indicated as follows:

	2006	2005
Proved properties	$13,387,369	$10,784,191
Unproved properties	506,482	389,198
Total	13,893,851	11,173,389
Accumulated depreciation, depletion and amortization	(5,949,804)	(5,086,210)
Net capitalized costs	$ 7,944,047	$ 6,087,179

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

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

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

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

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

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

United United

	States	Canada	Trinidad	Kingdom	Other	TOTAL
2006						
Acquisition Costs of Properties						
Unproved	$ 176,488	$ 43,248	$ 928	$ 5,035	$ -	$ 225,699
Proved	12,529	9,517	-	-	-	22,046
Subtotal	189,017	52,765	928	5,035	-	247,745
Exploration Costs	370,763	50,028	56,009	14,038	7,037	497,875
Development Costs (1)	1,813,269	339,602	79,712	17,945	-	2,250,528
Total	$ 2,373,049	$ 442,395	$ 136,649	$ 37,018	$ 7,037	$ 2,996,148
2005						
Acquisition Costs of Properties						
Unproved	$ 102,727	$ 24,278	$ 4,505	$ -	$ -	$ 131,510
Proved	55,477	468	-	-	-	55,945
Subtotal	158,204	24,746	4,505	-	-	187,455
Exploration Costs	286,862	42,426	19,924	18,040	2,844	370,096
Development Costs (2)	991,811	287,303	25,769	15,259	-	1,320,142
Total	$ 1,436,877	$ 354,475	$ 50,198	$ 33,299	$ 2,844	$ 1,877,693
2004						
Acquisition Costs of Properties						
Unproved	$ 129,230	$ 13,490	$ 74	$ -	$ -	$ 142,794
Proved	47,653	4,587	-	-	-	52,240
Subtotal	176,883	18,077	74	-	-	195,034
Exploration Costs	212,324	27,771	35,227	27,818	3,443	306,583
Development Costs (3)	666,443	277,045	48,618	33,133	-	1,025,239
Subtotal	1,055,650	322,893	83,919	60,951	3,443	1,526,856
Deferred Income Tax on Acquired Properties	-	(16,834)	-	-	-	(16,834)
Total	$ 1,055,650	$ 306,059	$ 83,919	$ 60,951	$ 3,443	$ 1,510,022

(1) Includes Asset Retirement Costs of $10 million, $6 million, $1 million and $5 million for the United States, Canada, Trinidad and the United Kingdom, respectively.
(2) Includes Asset Retirement Costs of $8 million, $11 million, $0 million and $1 million for the United States, Canada, Trinidad and the United Kingdom, respectively.

(3) Includes Asset Retirement Costs of $6 million, $7 million, $2 million and $2 million for the United States, Canada, Trinidad and the United Kingdom, respectively.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations for Oil and Gas Producing Activities(1)

. The following tables set forth results of operations for oil and gas producing activities for the years ended December 31:

	United States	Canada	Trinidad	United Kingdom	Other(2)	TOTAL
2006						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 2,539,037	$ 593,677	$ 345,677	$ 86,434	$ -	$ 3,564,825
Other, Net	4,861	(3)	11	461	-	5,330
Total	2,543,898	593,674	345,688	86,895	-	3,570,155
Exploration Costs	128,966	13,958	7,953	3,606	525	155,008
Dry Hole Costs	63,912	5,961	10,178	(484)	-	79,567
Production Costs	394,122	115,538	44,327	3,071	-	557,058
Transportation Costs	94,623	8,403	-	7,302	-	110,328
Impairments	89,374	18,884	-	-	-	108,258
Depreciation, Depletion and Amortization	623,311	143,368	26,623	23,787	-	817,089
Income Before Income Taxes	1,149,590	287,562	256,607	49,613	(525)	1,742,847
Income Tax Provision	413,194	82,776	102,699	24,807	-	623,476
Results of Operations	$ 736,396	$ 204,786	$ 153,908	$ 24,806	$ (525)	$ 1,119,371
2005						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 2,571,191	$ 651,349	$ 280,622	$ 103,828	$ -	$ 3,606,990
Other, Net	2,351	(1)	-	398	-	2,748
Total	2,573,542	651,348	280,622	104,226	-	3,609,738
Exploration Costs	112,143	11,512	5,243	4,218	-	133,116
Dry Hole Costs	20,090	24,372	2,571	17,779	-	64,812
Production Costs	344,094	87,069	39,135	1,042	-	471,340
Transportation Costs	68,693	9,227	-	9,019	-	86,939
Impairments	70,879	7,053	-	-	-	77,932
Depreciation, Depletion and Amortization	488,621	124,793	24,781	16,063	-	654,258
Income Before Income Taxes	1,469,022	387,322	208,892	56,105	-	2,121,341
Income Tax Provision	527,646	138,365	64,350	22,045	-	752,406
Results of Operations	$ 941,376	$ 248,957	$ 144,542	$ 34,060	$ -	$ 1,368,935

2004						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 1,687,646	$ 448,346	$ 153,377	$ 12,972	$ -	$ 2,302,341
Other, Net	2,128	205	-	-	-	2,333
Total	1,689,774	448,551	153,377	12,972	-	2,304,674
Exploration Costs	71,823	10,264	7,109	4,745	-	93,941
Dry Hole Costs	45,164	11,447	15,851	19,680	-	92,142
Production Costs	253,997	74,505	14,670	49	-	343,221
Transportation Costs	40,341	9,022	-	1,741	-	51,104
Impairments	68,309	13,221	-	-	-	81,530
Depreciation, Depletion and Amortization	382,718	99,879	20,022	1,784	-	504,403
Income (Loss) Before Income Taxes	827,422	230,213	95,725	(15,027)	-	1,138,333
Income Tax Provision (Benefit)	295,063	75,146	33,953	(7,230)	-	396,932
Results of Operations	$ 532,359	$ 155,067	$ 61,772	$ (7,797)	$ -	$ 741,401

(1) Excludes gains or losses on mark-to-market financial commodity derivative contracts, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2006.
(2) Other includes other international operations.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves.

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of EOG. The estimates were based on commodity prices at year-end. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

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

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

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	United States	Canada	Trinidad	United Kingdom	TOTAL
2006					
Future cash inflows(1)	$22,960,379	$ 7,326,752	$ 4,674,862	$ 93,031	$ 35,055,024
Future production costs	(6,928,994)	(2,398,427)	(592,840)	(40,995)	(9,961,256)
Future development costs	(2,083,736)	(395,270)	(422,979)	(7,942)	(2,909,927)
Future net cash flows before income taxes	13,947,649	4,533,055	3,659,043	44,094	22,183,841
Future income taxes	(4,096,634)	(988,737)	(1,450,026)	(22,047)	(6,557,444)
Future net cash flows	9,851,015	3,544,318	2,209,017	22,047	15,626,397
Discount to present value at 10% annual rate	(4,701,530)	(1,581,762)	(964,368)	(1,076)	(7,248,736)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 5,149,485	$ 1,962,556	$ 1,244,649	$ 20,971	$ 8,377,661
2005					
	$29,570,753	$11,699,916	$ 4,355,408	$ 447,719	$ 46,073,796

Future cash inflows[(2)]					
Future production costs	(7,623,688)	(2,824,960)	(617,551)	(50,027)	(11,116,226)
Future development costs	(1,565,491)	(362,191)	(268,306)	(12,482)	(2,208,470)
Future net cash flows before income taxes	20,381,574	8,512,765	3,469,551	385,210	32,749,100
Future income taxes	(6,349,537)	(2,524,804)	(1,311,384)	(146,492)	(10,332,217)
Future net cash flows	14,032,037	5,987,961	2,158,167	238,718	22,416,883
Discount to present value at 10% annual rate	(6,720,718)	(2,966,998)	(994,539)	(32,925)	(10,715,180)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 7,311,319	$ 3,020,963	$ 1,163,628	$ 205,793	$ 11,701,703
2004					
Future cash inflows	$17,044,764	$ 7,530,192	$ 3,419,365	$ 312,843	$ 28,307,164
Future production costs	(4,485,711)	(2,436,056)	(486,892)	(77,245)	(7,485,904)
Future development costs	(873,309)	(281,233)	(218,784)	(2,422)	(1,375,748)

Future net cash flows before income taxes	11,685,744	4,812,903	2,713,689	233,176	19,445,512
Future income taxes	(3,583,378)	(1,295,774)	(986,977)	(60,010)	(5,926,139)
Future net cash flows	8,102,366	3,517,129	1,726,712	173,166	13,519,373
Discount to present value at 10% annual rate	(3,795,487)	(1,570,232)	(809,757)	(25,919)	(6,201,395)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 4,306,879	$ 1,946,897	$ 916,955	$ 147,247	$ 7,317,978

(1) Estimated natural gas prices used to calculate 2006 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $5.18, $5.22, $3.10 and $4.72, respectively. Estimated liquids prices used to calculate 2006 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $51.63, $50.90, $56.82 and $55.98, respectively.
(2) Estimated natural gas prices used to calculate 2005 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $8.46, $8.51, $2.84 and $12.65, respectively. Estimated liquids prices used to calculate 2005 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $55.08, $50.39, $61.16 and $50.46, respectively.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006:

	United States	Canada	Trinidad	United Kingdom	TOTAL
December 31, 2003	$ 3,703,758	$ 1,744,215	$ 752,844	$ 113,298	$ 6,314,115
Sales and transfers of oil and gas produced, net of production costs	(1,393,308)	(364,819)	(138,707)	(11,182)	(1,908,016)
Net changes in prices and production costs	104,059	(148,876)	181,837	(20,213)	116,807
Extensions, discoveries, additions and improved recovery, net of related costs	1,247,934	385,547	8,564	-	1,642,045
Development costs incurred	130,000	88,900	97,000	9,500	325,400
Revisions of estimated development cost	77,986	8,058	(31,237)	5,138	59,945
Revisions of previous quantity estimates	(101,976)	(48,656)	56,372	1,252	(93,008)
Accretion of discount	521,398	224,582	112,510	18,258	876,748
Net change in income taxes	(143,615)	23,315	(124,614)	26,552	(218,362)
Purchases of reserves in place	79,703	15,543	-	-	95,246
Sales of reserves in place	(10,307)	(1,776)	-	-	(12,083)
Changes in timing and	91,247	20,864	2,386	4,644	119,141

other					
December 31, 2004	4,306,879	1,946,897	916,955	147,247	7,317,978
Sales and transfers of oil and gas produced, net of production costs	(2,158,404)	(555,053)	(241,487)	(93,767)	(3,048,711)
Net changes in prices and production costs	2,854,774	1,780,212	519,166	245,023	5,399,175
Extensions, discoveries, additions and improved recovery, net of related costs	2,694,823	384,295	-	132,470	3,211,588
Development costs incurred	183,800	46,700	25,300	11,100	266,900
Revisions of estimated development cost	(109,358)	(50,061)	(49,083)	(699)	(209,201)
Revisions of previous quantity estimates	(186)	36,687	26,408	(210,930)	(148,021)
Accretion of discount	600,528	242,519	141,383	18,998	1,003,428
Net change in income taxes	(1,341,611)	(513,951)	(148,222)	(81,811)	(2,085,595)
Purchases of reserves in place	135,759	-	-	-	135,759
Sales of reserves in place	(32,817)	-	-	-	(32,817)
Changes in timing and other	177,132	(297,282)	(26,792)	38,162	(108,780)
December 31, 2005	7,311,319	3,020,963	1,163,628	205,793	11,701,703

Sales and transfers of oil and gas produced, net of production costs	(2,050,290)	(469,736)	(301,350)	(76,061)	(2,897,437)
Net changes in prices and production costs	(3,898,956)	(1,766,233)	164,417	(212,730)	(5,713,502)
Extensions, discoveries, additions and improved recovery, net of related costs	1,837,039	327,281	38,100	-	2,202,420
Development costs incurred	312,900	50,700	37,400	8,093	409,093
Revisions of estimated development cost	(26,149)	(663)	557	(2,316)	(28,571)
Revisions of previous quantity estimates	(280,488)	(176,733)	(741)	(11,825)	(469,787)
Accretion of discount	1,035,133	401,320	180,872	33,034	1,650,359
Net change in income taxes	1,247,841	655,261	(130,573)	103,571	1,876,100
Purchases of reserves in place	23,473	2,732	-	-	26,205
Sales of reserves in place	(17,449)	(6,746)	-	-	(24,195)
Changes in timing and other	(344,888)	(75,590)	92,339	(26,588)	(354,727)
December 31, 2006	$ 5,149,485	$ 1,962,556	$1,244,649	$ 20,971	$ 8,377,661

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

Unaudited Quarterly Financial Information

(In Thousands, Except Per Share Data)

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
2006				
Net Operating Revenues	$ 1,084,536	$ 919,088	$ 968,248	$ 932,543
Operating Income	$ 628,428	$ 454,834	$ 461,788	$ 350,376
Income Before Income Taxes	$ 629,831	$ 464,294	$ 465,996	$ 352,520
Income Tax Provision	203,124	132,877	166,860	109,895
Net Income	426,707	331,417	299,136	242,625
Preferred Stock Dividends	1,858	1,858	1,858	5,421
Net Income Available to Common	$ 424,849	$ 329,559	$ 297,278	$ 237,204
Net Income Per Share Available to Common(1)				
Basic	$ 1.76	$ 1.36	$ 1.23	$ 0.98
Diluted	$ 1.73	$ 1.34	$ 1.21	$ 0.96
Average Number of Common Shares				
Basic	241,118	241,613	241,911	242,515
Diluted	245,923	245,887	246,136	246,477

2005

Net Operating Revenues	$ 688,156	$ 783,924	$ 934,445	$ 1,213,688
Operating Income	$ 320,095	$ 394,689	$ 522,156	$ 754,875
Income Before Income Taxes	$ 311,603	$ 386,876	$ 518,438	$ 748,220
Income Tax Provision	108,900	137,420	174,677	284,564
Net Income	202,703	249,456	343,761	463,656
Preferred Stock Dividends	1,858	1,858	1,857	1,859
Net Income Available to Common	$ 200,845	$ 247,598	$ 341,904	$ 461,797
Net Income Per Share Available to Common[1]				
Basic	$ 0.85	$ 1.04	$ 1.43	$ 1.92
Diluted	$ 0.83	$ 1.02	$ 1.40	$ 1.88
Average Number of Common Shares				
Basic	237,293	238,252	239,344	240,427
Diluted	242,114	243,414	244,900	245,463

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

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2006, 2005 and 2004

(In Thousands)

Description	Column B Balance at Beginning of Year	Column C Additions Charged to Costs and Expenses	Column D Deductions From Reserves	Column E Balance at End of Year
2006				
Allowance deducted from Accounts Receivable	$ 21,806	$ 24	$ 4,531	$ 17,299
2005				
Allowance deducted from Accounts Receivable	$ 20,619	$ 1,679	$ 492	$ 21,806
2004				
Allowance deducted from Accounts Receivable	$ 20,748	$ 45	$ 174	$ 20,619

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EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to EOG's Form S-1 Registration Statement, Registration No. 33-30678, filed on August 24, 1989 (Form S-1), or as otherwise indicated.

Exhibit Number		Description
3.1(a)	-	Restated Certificate of Incorporation (Exhibit 3.1 to Form S-1).
3.1(b)	-	

		Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 4.1(b) to Form S-8 Registration Statement No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 4.1(c) to Form S-8 Registration Statement No. 33-58103, filed March 15, 1995).
3.1(d)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to Form S-3 Registration Statement No. 333-09919, filed August 9, 1996).
3.1(e)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to Form S-3 Registration Statement No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to Form 8-A Registration Statement, filed February 18, 2000).
3.1(h)	-	Certificate of Designation, Preferences and Rights of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated July 19, 2000 (Exhibit 3.1(h) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 15, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 15, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3 Registration Statement No. 333-46858, filed September 28, 2000).
3.1(k)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004).
3.1(l)	-	Certificate of Amendment to Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
3.2	-	By-laws, dated August 23, 1989, as amended and restated effective as of February 24, 2004 (Exhibit 3.2 to EOG's Annual Report on Form 10-K for the year ended December 31, 2003).
4.1(a)	-	Specimen of Certificate evidencing the Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999).
4.1(b)	-	Specimen of Certificate Evidencing Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B (Exhibit 4.3(g) to EOG's Registration Statement on Form S-4 Registration Statement No. 333-36056, filed June 7, 2000).

Exhibit Number		Description

4.2	-	Rights Agreement, dated as of February 14, 2000, between EOG and First Chicago Trust Company of New York, which includes the form of Rights Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C (Exhibit 1 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.3	-	Form of Rights Certificate (Exhibit 3 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.4	-	Indenture dated as of September 1, 1991, between EOG and JPMorgan Chase Bank, National Association (formerly, Texas Commerce Bank National Association) (Exhibit 4(a) to EOG's Registration Statement on Form S-3 Registration Statement No. 33-42640, filed September 6, 1991).
4.5	-	Amendment, dated as of December 13, 2001, to the Rights Agreement, dated as of February 14, 2000, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 2 to Amendment No. 1 to EOG's Registration Statement on Form 8-A/A filed December 14, 2001).
4.6	-	Letter dated December 13, 2001, from First Chicago Trust Company of New York to EOG resigning as rights agent effective January 12, 2002 (Exhibit 3 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.7	-	Amendment, dated as of December 20, 2001, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 4 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.8	-	Letter dated December 20, 2001, from EOG Resources, Inc. to EquiServe Trust Company, N.A. appointing EquiServe Trust Company, N.A. as successor rights agent (Exhibit 5 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A filed February 7, 2002).
4.9	-	Amendment, dated as of April 11, 2002, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed April 12, 2002).
4.10	-	Amendment, dated as of December 10, 2002, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed December 11, 2002).
4.11	-	Amendment, dated as of February 24, 2005, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.12 to EOG's Annual Report on Form 10-K for the year ended December 31, 2004).
4.12	-	Amendment, dated as of June 15, 2005, to the Rights Agreement, dated as of February 14, 2000, as amended, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.1(a)	-	Amended and Restated 1994 Stock Plan (Exhibit 4.3 to Form S-8 Registration Statement No. 33-58103, filed March 15, 1995).
10.1(b)	-	Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 12, 1995 (Exhibit 4.3(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1995).

10.1(c)	-	Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 10, 1996 (Exhibit 4.3(a) to Form S-8 Registration Statement No. 333-20841, filed January 31, 1997).

Exhibit Number		Description
10.1(d)	-	Third Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 9, 1997 (Exhibit 4.3(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 1997).
10.1(e)	-	Fourth Amendment to Amended and Restated 1994 Stock Plan, dated effective as of May 5, 1998 (Exhibit 4.3(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998).
10.1(f)	-	Fifth Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 8, 1998 (Exhibit 4.3(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998).
10.1(g)	-	Sixth Amendment to Amended and Restated 1994 Stock Plan, dated effective as of May 8, 2001 (Exhibit 10.1(g) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001).
10.1(h)	-	Seventh Amendment to Amended and Restated 1994 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.1(h) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.2(a)	-	Amended and Restated 1993 Nonemployee Directors Stock Option Plan (Exhibit A to EOG's Proxy Statement, dated March 28, 2002, with respect to EOG's Annual Meeting of Shareholders).
10.2(b)	-	First Amendment to Amended and Restated 1993 Nonemployee Directors Stock Option Plan, dated effective as of December 30, 2005 (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.3(a)	-	Amended and Restated 1992 Stock Plan (Exhibit B to EOG's Proxy Statement, dated March 29, 2004, with respect to EOG's Annual Meeting of Shareholders).
10.3(b)	-	First Amendment to Amended and Restated 1992 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.3(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.4(a)	-	Amended and Restated 1996 Deferral Plan (Exhibit 4.4 to Form S-8 Registration Statement No. 333-84014, filed March 8, 2002).
10.4(b)	-	First Amendment to Amended and Restated 1996 Deferral Plan, effective as of September 10, 2002 (Exhibit 10.9(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2002).
10.5(a)	-	Executive Employment Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.1 to EOG's Current Report on Form 8-K filed, June 21, 2005).

10.5(b)	-	Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.6 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.6(a)	-	Executive Employment Agreement between EOG and Edmund P. Segner, III, effective as of June 15, 2005 (Exhibit 99.2 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.6(b)	-	Amended and Restated Change of Control Agreement between EOG and Edmund P. Segner, III, effective as of June 15, 2005 (Exhibit 99.7 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(a)	-	Executive Employment Agreement between EOG and Barry Hunsaker, Jr., effective as of June 15, 2005 (Exhibit 99.5 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(b)	-	Amended and Restated Change of Control Agreement between EOG and Barry Hunsaker, Jr., effective as of June 15, 2005 (Exhibit 99.10 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.8(a)	-	Executive Employment Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.3 to EOG's Current Report on Form 8-K, filed June 21, 2005).

Exhibit Number		Description
9;		
10.8(b)	-	Amended and Restated Change of Control Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.8 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.9(a)	-	Executive Employment Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.4 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.9(b)	-	Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.9 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.10(a)	-	Amended and Restated Change of Control Severance Plan, effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.11	-	Executive Officer Annual Bonus Plan (Exhibit C to EOG's Proxy Statement, dated March 30, 2001, with respect to EOG's Annual Meeting of Shareholders).
10.12	-	Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.13(a)	-	Revolving Credit Agreement, dated June 28, 2005, among EOG Resources, Inc., JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30,

		2005).
10.13(b)	-	First Amendment, dated June 21, 2006, to Revolving Credit Agreement, dated June 28, 2005, among EOG Resources, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.14	-	Senior Term Loan Agreement, dated October 28, 2005, among EOG Resources, Inc., as Parent Guarantor, EOGI International Company, as Borrower, The Bank of Nova Scotia, as Administrative Agent, and the financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2005).
*12	-	Computation of Ratio of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
*21	-	List of subsidiaries.
*23.1	-	Consent of DeGolyer and MacNaughton.
*23.2	-	Opinion of DeGolyer and MacNaughton dated January 29, 2007.
*23.3	-	Consent of Deloitte & Touche LLP.
*24	-	Powers of Attorney.
*31.1	-	Section 302 Certification of Annual Report of Chief Executive Officer.
*31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
*32.1	-	Section 906 Certification of Annual Report of Chief Executive Officer.
*32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: February 26, 2007 By: /s/ TIMOTHY K. DRIGGERS

Timothy K. Driggers
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of registrant and in the capacities with EOG Resources, Inc. indicated and on the 26th day of February, 2007.

Signature	Title
/s/ MARK G. PAPA (Mark G. Papa)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ EDMUND P. SEGNER, III (Edmund P. Segner, III)	Senior Executive Vice President and Chief of Staff and Director (Principal Financial Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Vice President and Chief Accounting Officer (Principal Accounting Officer)
*GEORGE A. ALCORN (George A. Alcorn)	Director
*CHARLES R. CRISP (Charles R. Crisp)	Director
*WILLIAM D. STEVENS (William D. Stevens)	Director
*H. LEIGHTON STEWARD (H. Leighton Steward)	Director
*DONALD F. TEXTOR (Donald F. Textor)	Director
*FRANK G. WISNER (Frank G. Wisner)	Director

* /s/ PATRICIA L. EDWARDS
(Patricia L. Edwards)
(Attorney-in-fact for persons indicated)

EOG RESOURCES, INC. AND SUBSIDIARIES
EXHIBITS TO FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006
INDEX OF EXHIBITS

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*24 - Powers of Attorney.

*31.1 - Section 302 Certification of Annual Report of Chief Executive Officer.

*31.2 - Section 302 Certification of Annual Report of Principal Financial Officer.

*32.1 - Section 906 Certification of Annual Report of Chief Executive Officer.

*32.2 - Section 906 Certification of

Annual Report of Principal Financial Officer.

*Exhibits filed herewith.