EOG RESOURCES INC
Form 10-K
February 28, 2008

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, 2007

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.)

1111 Bagby, Sky Lobby 2, Houston, Texas 77002

(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 the 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x   Accelerated filer o   Non-accelerated filer o   Smaller reporting company 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 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 June 30, 2007: $17,881,411,475.

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, 247,019,188 Shares outstanding as of February 15, 2008.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2008 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2007 are incorporated by reference into Part III of this report.

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PART I

ITEM 1. *Business*

General

EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively EOG), 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 any 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, 2007, EOG's total estimated net proved reserves were 7,745 billion cubic feet equivalent (Bcfe), of which 6,669 billion cubic feet (Bcf) were natural gas reserves and 179 million barrels (MMBbl), or 1,076 Bcfe, were crude oil, condensate and natural gas liquids reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 67% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 17% in Canada and 16% in Trinidad. As of December 31, 2007, EOG employed approximately 1,800 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, horizontal drilling, well completion 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 strategic acquisitions that result in additional economies of scale or land positions which provide 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, 2007, 84% of EOG's net proved United States and Canada reserves (on a natural gas equivalent basis) were natural gas and 16% 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 the 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 2007 and certain 2008 plans for EOG's United States and Canada operations.

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United States

. In the prolific Barnett Shale play of the Fort Worth Basin, EOG, which holds approximately 900,000 net acres, has become an industry leader in per well production rates through the application of advanced drilling and completion technology. In 2007, EOG continued a very active drilling program and had strong production growth. For the year, EOG drilled 293 net wells and grew production to a net average of 271 million cubic feet per day (MMcfd) of natural gas and 2.2 thousand barrels per day (MBbld) of crude oil, condensate and natural gas liquids. EOG ended 2007 with production of approximately 375 million cubic feet equivalent per day (MMcfed), net and expects to significantly grow production during 2008 with the plan to drill and complete over 400 net wells. Using innovative technology, EOG is generating significant new growth opportunities in the Fort Worth Basin that are expected to add to its future reserve and production growth potential.

The Upper Gulf Coast continued to be a growth area for EOG where 2007 net production grew 12% year over year and averaged 135 MMcfd of natural gas and 3.5 MBbld of crude oil, condensate and natural gas liquids. In 2007, EOG drilled 90 net wells in the Upper Gulf Coast area with 67 net wells in the Sligo, Minden, Carthage, Driscoll, Logansport and Appleby Fields of the Cotton Valley and Travis Peak formations in East Texas and North Louisiana. Mississippi remained a major growth area where 23 successful net wells were drilled in the Sligo and Hosston plays in South Williamsburg and two new discoveries were made in the Columbia and Whitesand Fields. EOG is currently one of the largest natural gas producers in Mississippi. EOG, which holds approximately 300,000 net acres in the Upper Gulf Coast area, will continue its growth in East Texas, Louisiana and Mississippi and plans to test several high potential impact new projects in 2008.

During 2007, EOG drilled 55 net wells in the Permian Basin, with 33 net wells drilled in the New Mexico Wolfcamp play. EOG has acquired 50,000 acres in the play and plans to drill a similar number of wells in 2008. EOG also had success with vertical oil wells in the Permo-Penn carbonates as well as horizontal wells in the Bone Spring sand. Net production averaged 82 MMcfd of natural gas and 6.9 MBbld of crude oil, condensate and natural gas liquids. Program economics remained strong through 2007 as significant acreage and new 3-D seismic data were acquired in several trends, setting up new plays for 2008 and beyond. EOG holds approximately 450,000 net acres in the Permian Basin.

EOG continued to expand its activities throughout the Rocky Mountain area where it holds approximately 1.3 million net acres. During 2007, 267 net wells were drilled. In the core areas, 187 net wells were drilled in the Uinta Basin, Utah, 38 net wells were drilled in the Moxa Arch area of Wyoming, 20 net wells were drilled in the Williston Basin, North Dakota and 19 net wells were drilled in the LaBarge Platform, Wyoming. Production from the Rocky Mountain area increased 15% with the increased drilling activity. The net average production for 2007 was 178 MMcfd of natural gas and 11.9 MBbld of crude oil, condensate and natural gas liquids. EOG expects to continue increasing exploitation drilling activity throughout the Rocky Mountain area during 2008, while maintaining an active exploration program. EOG ended 2007 producing approximately 7.0 MBbld, net, of crude oil from the Bakken play in North Dakota and will seek to significantly grow production during 2008 with 49 net wells planned.

In the Mid-Continent area, EOG drilled 117 net wells during 2007 in the Hugoton-Deep play in the Southwest Kansas/Oklahoma Panhandle and the Cleveland Horizontal play in the Texas Panhandle. The net average production for 2007 was 80 MMcfd of natural gas and 3.5 MBbld of crude oil and condensate which represents a 14% total production increase over 2006. EOG continued its strong exploration program in Southwest Kansas and was successful in finding several new Morrow and St. Louis plays. As part of the Hugoton-Deep play, EOG has eight years remaining on an approximately 900,000 gross acre, 10-year farm-in agreement from Anadarko Petroleum Company. EOG plans to continue exploiting these two core growth areas in 2008, while pursuing other exploration prospects throughout the Mid-Continent area. EOG holds approximately 500,000 net acres in the Mid-Continent area.

EOG had another successful year in South Texas and the Gulf of Mexico, drilling 91 net wells in 2007. South Texas onshore and Gulf of Mexico offshore net production averaged 209 MMcfd of natural gas and 7.8 MBbld of crude oil, condensate and natural gas liquids during 2007. 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 continues to expand into new areas. EOG is acquiring seismic data and leases to expand horizontal drilling technology to three additional trends in South Texas. Production from two deepwater Gulf of Mexico wells, drilled in the Atwater Valley area that was discovered in 2001, is expected to commence during the first quarter of 2008 at an initial rate of 10 MMcfd, net. Plans are to increase this rate to approximately 20 MMcfd, net after additional facilities are installed

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in mid-2008. Approximately 92 net wells are planned during 2008 for South Texas and the Gulf of Mexico where EOG holds approximately 550,000 net acres.

In 2007, EOG drilled 51 net wells in the Appalachian Basin where it holds approximately 310,000 net acres. Net production averaged 17 MMcfd of natural gas and 60 barrels per day of crude oil and condensate. A majority of the wells were drilled in the shallow Devonian play and 10 gross wells were drilled to evaluate the deeper Marcellus Shale. In December 2007, EOG entered into an agreement to sell the majority of its producing shallow gas assets and surrounding acreage in the Appalachian Basin to a subsidiary of EXCO Resources, Inc., an independent oil and gas company, for approximately $395 million, subject to customary adjustments under the agreement. The Appalachian area being divested includes approximately 2,400 operated wells that accounted for approximately 1% of EOG's total 2007 production and approximately 2% of its total year-end 2007 proved reserves. The transaction closed on February 20, 2008. EOG retained certain of its undeveloped acreage in this area, including rights in the Marcellus Shale, and will continue its shale exploration program. During 2008, EOG will continue to drill and evaluate the Marcellus Shale in Pennsylvania using horizontal drilling and completion techniques.

As December 31, 2007, EOG held approximately 3,204,000 net undeveloped acres in the United States.

As EOG begins to operate in areas where there is limited infrastructure, EOG is placing more emphasis on gathering and processing operations to support its production activities. This additional emphasis resulted in the formation of Pecan Pipeline Company (Pecan) and Pecan Pipeline (North Dakota), Inc. (Pecan North Dakota), each a wholly owned subsidiary of EOG. Pecan has installed two natural gas gathering systems in the Barnett Shale play of North Texas, and Pecan North Dakota began the installation of an associated natural gas gathering and processing system in the Bakken Shale play of North Dakota. The Texas systems total approximately 21 miles of 10 inch and 20 inch diameter lines. At year-end 2007, throughput was approximately 27 MMcfd of natural gas. Additional pipeline and processing facilities are planned for North Texas during 2008. Initial operation of the North Dakota system is expected in the first quarter of 2008 with capacity to gather and process approximately 3 MMcfd of associated natural gas from the Bakken oil wells. During 2008, an expansion of this system is planned that is expected to increase capacity to approximately 20 MMcfd of associated natural gas.

Canada.

EOG conducts operations through its subsidiary, EOG Resources Canada Inc. (EOGRC), from offices in Calgary, Alberta. During 2007, EOGRC continued its successful shallow gas strategy in Western Canada, drilling a total of 731 net wells. 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 drilled one vertical and three horizontal shale gas wells in the Horn River Basin in Northeastern British Columbia during 2007 and has plans to drill several additional horizontal shale wells in 2008. Details on this play are expected to be released during 2008. In the fourth quarter of 2007, EOGRC divested all its exploration properties in the Northwest Territories as the timeframe for an export pipeline became longer and more problematic. A royalty review was undertaken by the Alberta government, which resulted in a revamping of the royalty structure within Alberta, effective January 2009. EOGRC's analysis determined that these changes will not have a material impact on net after royalty production, largely due to the fact that the new royalty structure is favorable to lower productivity, shallow gas wells at current pricing. EOGRC's net production during 2007 averaged 224 MMcfd of natural gas and 3.5 MBbld of crude oil, condensate and natural gas liquids. EOGRC plans to drill at least 600 net wells during 2008.

At December 31, 2007, EOGRC held approximately 1,250,000 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 in 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). In the SECC Block, the Kiskadee, Ibis and Parula fields have been developed and are being produced. In June 2007, EOG finalized the development drilling of the Oilbird Field. Initial production is expected in the first quarter of 2008 pending completion of the new National Gas Company of Trinidad and Tobago (NGC) gas pipeline. Effective September 1,

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J006, the Oilbird Field Unitization Agreement was executed as the Oilbird Field straddles the SECC Block and the Modified 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, located on the Modified U(a) Block, 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 the SECC Block, Modified U(a) Block and the Modified U(b) Block. Crude oil and condensate from EOG's Trinidad operations are being sold to the Petroleum Company of Trinidad and Tobago. In 2007, EOG agreed to purchase an 80% interest in the Pelican field facilities from the subsidiaries of the other participants in the SECC Block. The transaction is expected to close in the first quarter of 2008.

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 November 2004, EOG drilled the LRL #2 well which encountered approximately 130 feet of net pay. EOG continues to evaluate development options for the LRL #2 discovery.

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, as the operator, originally held a 55% working interest in the Modified U(b) Block. In May 2007, EOG acquired the remainder of the interest in the Modified U(b) Block from Primera Oil & Gas Ltd., a Trinidadian company, and now holds a 100% working interest in the Modified U(b) Block. In August 2007, EOG drilled the U(b)-2 exploratory well on this Block, and the well was determined to be non-commercial. As noted above, effective September 1, 2006, the Oilbird Field Unitization Agreement was executed as the Oilbird Field straddles the SECC Block and the Modified 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, originally held a 90% working interest in Block 4(a). In March 2007, EOG acquired the remaining 10% working interest from Primera Block 4(a) Limited, a Trinidadian company, and now holds a 100% working interest in Block 4(a). 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 15-year gas sales contract with NGC for the sale of approximately 100 MMcfd, gross (78 MMcfd, net to EOG, based on current pricing and operating assumptions). EOG expects to begin initial delivery under the contract in early 2010 from its first discovery on Block 4(a), subject to completion of a pipeline by NGC.

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 2018, natural gas is delivered to NGC for resale to Trinidad local markets. During 2007, EOG delivered net average production of 124 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 2007, 25 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, 2007, EOGRT's investment in CNCL was $19 million. At December 31, 2007, CNCL had a long-term debt balance of $111 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. Since inception, there have been no borrowings under this agreement. 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 2007, EOG recognized equity income of $8 million and received cash dividends of $8 million from CNCL.

- Under a 15-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 2007, 26 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, 2007, EOGNitro2000's investment in N2000 was $17 million. At December 31, 2007, N2000 had a long-term debt balance of $136 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. Since inception, there have been no borrowings under this agreement. 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 2007, EOG recognized equity income of $8 million and received cash dividends of $8 million from N2000.

- Under a 15-year contract signed in January 2004, EOG is supplying 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 95 MMcfd, gross, (70 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 115 MMcfd, gross, (85 MMcfd, net to EOG, based on current pricing and operating assumptions) for the remaining term of the contract. During 2007, 70 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC.

- In January 2005, EOGRT executed a 20-year take-or-pay contract with NGC LNG (Train 4) Limited, a subsidiary of NGC, for the supply of approximately 30 MMcfd, gross, (12 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. EOG delivered gas at the contractual rate of 30 MMcfd, gross (12 MMcfd, net) beginning in May 2007 when the ALNG plant reached commercial status. During 2007, 7 MMcfd, net to EOG, of natural gas was delivered under this contract to NGC.

- In July 2007, EOG executed a 15-year natural gas contract with NGC for the sale of approximately 100 MMcfd, gross (78 MMcfd, net to EOG, based on current pricing and operating assumptions). EOG expects to begin initial delivery under this contract in early 2010 from its first discovery on Block 4(a), subject to the completion of a pipeline by NGC.

During 2007, EOG executed a one-year term sheet, effective July 1, 2007, with the Petroleum Company of Trinidad and Tobago that sets forth the pricing for the sales of crude oil and condensate produced in Trinidad. The pricing terms are based on the valuation of the distillation yield of the crude oil and condensate produced less a refining margin. This term sheet replaces the pricing provisions of a previous crude oil and condensate sales contract

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that expired on June 30, 2007 and will be incorporated into a new crude oil and condensate sales contract which is expected to be finalized during the first quarter of 2008.

In 2007, EOG's average net production from Trinidad was 252 MMcfd of natural gas and 4.1 MBbld of crude oil and condensate.

At December 31, 2007, EOG held approximately 233,000 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.

In 2006, EOG participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. In 2007, a successful appraisal well was drilled on this prospect. The future development of this prospect is currently being evaluated. EOG also participated in the drilling of an unsuccessful exploratory well in August 2007 on the Eos prospect located in the Southern North Sea Block 45/11c.

In 2007, EOG delivered net average production of 23 MMcfd of natural gas in the United Kingdom.

At December 31, 2007, EOG held approximately 177,000 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 based on prevailing market prices. In many instances, the long-term contract prices closely approximate the prices received for natural gas being sold on the spot market. In 2007, 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 2008. In 2007, 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 2008.

Substantially all of EOG's wellhead crude oil and condensate is sold under various terms and arrangements based on prevailing market prices.

During 2007, no single purchaser accounted for 10% or more of EOG's natural gas and crude oil revenues. EOG does not believe that the loss of any single purchaser would have a material adverse effect on its financial condition or results of operations.

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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, 2007.

	2007	2006	2005
Natural Gas Volumes (MMcfd)			
United States	971	817	718
Canada	224	226	228
Trinidad	252	264	231
United Kingdom	23	30	39
Total	1,470	1,337	1,216
Crude Oil and Condensate Volumes (MBbld)			
United States	24.6	20.7	21.5

Canada	2.4	2.5	2.4
Trinidad	4.1	4.8	4.5
United Kingdom	0.1	0.1	0.2
Total	31.2	28.1	28.6
Natural Gas Liquids Volumes (MBbld)			
United States	11.1	8.5	6.6
Canada	1.1	0.8	0.9
Total	12.2	9.3	7.5
Natural Gas Equivalent Volumes (MMcfed) (1)			
United States	1,184	992	886
Canada	245	246	248
Trinidad	276	292	259
United Kingdom	24	31	40
Total	1,729	1,561	1,433
Average Natural Gas Prices ($/Mcf) (2)			
United States	$ 6.32	$ 6.56	$ 7.86
Canada	6.25	6.41	7.14
Trinidad	2.71	2.44	2.20
United Kingdom	6.19	7.69	6.99
Composite	5.69	5.74	6.62
Average Crude Oil and Condensate Prices ($/Bbl) (2)			
United States	$ 68.85	$ 62.68	$ 54.57
Canada	65.27	57.32	50.49
Trinidad	69.84	63.87	57.36
United Kingdom	66.84	57.74	49.62
Composite	68.69	62.38	54.63
Average Natural Gas			

Liquids Prices ($/Bbl) (2)			
United States	$47.63	$39.95	$35.59
Canada	44.54	43.69	35.59
Composite	47.36	40.25	35.59

(1) Million cubic feet equivalent per day; includes natural gas, crude oil, condensate and natural gas liquids.
(2) Dollars per thousand cubic feet or per barrel, as applicable.

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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.

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, New Mexico, 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 such facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although

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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 greenhouse gas (GHG) emissions and climate change issues. EOG believes that its strategy to reduce GHG 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 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, could increase EOG's costs and may have a material adverse impact on EOG's operations and financial condition.

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; however, EOG is unable to predict what additional legislation or amendments may be enacted or how such additional legislation or amendments may affect EOG's operations and financial condition.

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.

In October 2007, the Alberta Government announced a new oil and gas royalty framework to take effect in January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties will be set by a

sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil will range from 0% to 50%. New natural gas royalty rates will range from 5% to 50%.

The implementation of the new framework is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software to support the calculation and collection of royalties. In addition, certain proposed changes contemplate further public and/or industry consultation. Accordingly, there may be modifications introduced to the new framework prior to its implementation in January 2009.

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. Compliance with such laws and regulations increases EOG's overall cost of business, but has not had, to date, 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 or the effect on EOG's operations and financial condition.

Spills and releases from EOG's properties may have resulted, or may 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. 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 Canadian 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 held responsible for oil and gas properties in which EOG owns an interest but is not the operator.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. In response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (Regulatory Framework) for regulating air pollution and industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to come into effect in 2010 and targets would be based on percentages rather than absolute reductions. The Regulatory Framework also proposes a credit emissions trading system. Additionally, regulation can take place at the provincial and municipal level. For example, Alberta introduced the *Climate Change and Emissions Management Act*, which provides a framework for managing GHG by reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020 and which imposes duties to report. The accompanying regulation, the *Specified Gas Emitters Regulation*, which became effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets. The direct and indirect costs of these regulations may adversely affect EOG's business, results of operations and financial condition.

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.

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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 3% decrease in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2006 to 2007, a decrease of 15% from 2005 to 2006, and an increase of 37% from 2004 to 2005. In 2007, 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 2008. In 2007, 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 2008. 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, natural gas liquids, ammonia and methanol prices in the future. For additional discussion regarding changes in natural gas and crude oil prices and the risks that such changes may present to EOG, see ITEM1A. Risk Factors.

Including the impact of EOG's 2008 natural gas and crude oil hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2008 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 $20 million for net income and operating cash flow. EOG's price sensitivity in 2008 for each $1.00 per barrel change in wellhead crude oil price, combined with the related change in natural gas liquids prices, is approximately $10 million for net income and operating cash flow. For information regarding EOG's natural gas and crude oil hedge position as of December 31, 2007, see Note 11 to Consolidated Financial Statements.

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 to manage 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 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 - Capital Resources and Liquidity - 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 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 - Results of Operations - Operating and Other Expenses.

Executive Officers of the Registrant

The current executive officers of EOG and their names and ages (as of February 28, 2008) are as follows:

Name	Age	Position
Mark G. Papa	61	Chairman of the Board and Chief Executive Officer; Director

Loren M. Leiker	54	Senior Executive Vice President, Exploration
Gary L. Thomas	58	Senior Executive Vice President, Operations
Robert K. Garrison	55	Executive Vice President, Exploration
Fredrick J. Plaeger, II	54	Senior Vice President and General Counsel
Timothy K. Driggers	46	Vice President and Chief Financial 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, and President in December 1996, and was President-North America Operations from February 1994 to December 1996. Mr. Papa joined Belco Petroleum Corporation, a predecessor of EOG, in 1981. Mr. Papa is currently a director of Oil States International, Inc., an oilfield service company. Mr. Papa is EOG's principal executive officer.

Loren M. Leiker was elected Senior Executive Vice President, Exploration in February 2007. He was elected Executive Vice President, Exploration in May 1998 and was subsequently named Executive Vice President, Exploration and Development in January 2000. He was previously Senior Vice President, Exploration. Mr. Leiker joined EOG in April 1989.

Gary L. Thomas was elected Senior Executive Vice President, Operations in February 2007. He was elected Executive Vice President, North America Operations in May 1998 and was subsequently named Executive Vice President, Operations in May 2002. He was previously Senior Vice President and General Manager of EOG's Midland, Texas office. Mr. Thomas joined a predecessor of EOG in July 1978.

Robert K. Garrison was elected Executive Vice President, Exploration in February 2007. He was elected Senior Vice President and General Manager of EOG's Corpus Christi, Texas office in August 2004 and, prior to such election, was Vice President and General Manger of EOG's Corpus Christi, Texas office. Mr. Garrison joined EOG in April 1995.

Frederick J. Plaeger, II joined EOG as Senior Vice President and General Counsel in April 2007. He served as Vice President and General Counsel of Burlington Resources Inc., an independent oil and natural gas exploration and production company, from June 1998 until its acquisition by ConocoPhillips in March 2006. Mr. Plaeger engaged exclusively in leadership roles in professional legal associations from April 2006 until April 2007.

Timothy K. Driggers was elected Vice President and Chief Financial Officer in July 2007. He was elected Vice President and Controller of EOG in October 1999 and was subsequently named Vice President, Accounting and Land Administration in October 2000 and Vice President and Chief Accounting Officer in August 2003. Mr. Driggers is EOG's principal financial and accounting officer. Mr. Driggers joined EOG in October 1999.

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ITEM 1A. *Risk Factors*

Our business and operations are subject to many risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could be materially and adversely affected 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 natural and extent of governmental regulation and taxation, including environmental regulations.

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 materially and adversely affect our liquidity, the amount of cash flow we have available for capital expenditures, our ability to maintain our credit quality and access to the credit and capital markets and our results of operations.

Our ability to sell our crude oil and natural gas production could be materially affected 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. Moreover, we deliver crude oil and natural gas through gathering systems and pipelines that we do not own, and these facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future. Any significant change in market factors affecting these facilities, the availability of these facilities or our failure or inability to obtain access to these facilities on terms acceptable to us or at all could materially and adversely affect our business and, in turn, our financial condition and results of operations.

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

Demand for natural gas and crude 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 extreme weather conditions, such as hurricanes in the Gulf of Mexico, and sea level changes associated with climate change, which may cause a loss of production from temporary cessation of activity or lost or damaged equipment. Extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the installation of new facilities. Such extreme weather conditions and changes associated with climate change could materially and adversely affect our business and, in turn, our financial condition and results of operations.

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

Estimating quantities of proved natural gas and crude oil reserves and future net cash flows from such 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 in conditions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated.

To prepare estimates of economically recoverable natural gas and crude oil reserves and future net cash flows from our reserves, 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. Our actual proved reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance could reduce our estimated quantities and present value of reserves, which could, in turn, materially and adversely affect our business, financial condition and results of operations and the trading price of our common stock.

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. Our future natural gas and crude oil production, specifically maintaining our production at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

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

Drilling natural gas and crude oil wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive natural gas and crude oil reservoirs. As a result, 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, among other factors, may cause our drilling activities to be unsuccessful and result in a partial or total loss of our investment. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, as our drilling operations may be curtailed, delayed or canceled, and the cost of such operations may increase, 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 the governments and regulatory agencies in foreign countries in which we do business. We have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental and other regulations. Further, the regulatory environment in the natural gas and crude oil industry could change in ways that we cannot predict and that might substantially increase our costs of compliance.

As an owner or lessee and operator of natural gas and crude oil 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 cleanup 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 materially and adversely affect our business, financial condition and results of operations.

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EOG is aware of the increasing focus of national and international regulatory bodies on GHG emissions and climate change issues. We are also aware of legislation, recently proposed by the Canadian legislature, to reduce GHG emissions. Additionally, proposed United States policy, legislation or regulatory actions may also address GHG emissions. EOG will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary.

We do not insure against all potential losses and could be materially and adversely affected by unexpected liabilities.

The exploration for, and production of, natural gas and crude oil 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. Moreover, our 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 and at costs that we believe to be prudent and commercially practicable. The occurrence of any of these events and any costs or liabilities incurred as a result of such events would reduce the funds available to us for exploration, drilling and production and could, in turn, have a material adverse effect on our business, financial condition and 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 our 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 natural gas and crude oil volumes to the delivery point to which the hedging transaction is indexed.

If we acquire natural gas and crude oil 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 materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire natural gas and crude oil properties. Although we perform reviews of properties to be acquired 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 in order 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 pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of proved natural gas and crude oil reserves, actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in the estimates. In addition, acquisitions may have material and adverse effects on our business and results of operations, 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 materially and adversely affect us.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could 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 materially and adversely affect us in unpredictable ways, including the disruption of fuel supplies and markets, increased volatility in natural gas and crude oil prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, which, in turn, could materially and adversely affect our business, financial condition and results of operations.

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 natural gas and crude oil leases, properties and reserves, equipment and labor required to explore, develop and operate those properties and the marketing of natural gas and crude oil production. Higher recent natural gas and crude oil prices have increased the costs of properties available for acquisition, and there are several companies with the financial resources to pursue acquisition opportunities.

In addition, many of our competitors have financial and other resources substantially greater than those we possess and have established strategic long-term positions and 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 natural gas and crude oil, 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 with our competitors 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 natural gas and crude oil reserves. We intend to finance our capital expenditures primarily through our cash flow from operations and commercial paper borrowings and, to a lesser extent and if and as necessary, bank borrowings and public and private equity and debt offerings.

Lower natural gas and crude oil prices, however, would 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. The recent credit crisis triggered by the subprime mortgage markets and corresponding reaction by lenders to risk, generally, may increase the interest rates that the lenders require us to pay. In addition, a substantial rise in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations.

Unfavorable currency exchange rate fluctuations could adversely affect our results of operations.

The reporting currency for our financial statements is the U.S. dollar. However, certain of our subsidiaries are located in countries other than the United States and have functional currencies other than the U.S. dollar. The assets, liabilities, revenues and expenses of certain of these foreign subsidiaries are denominated in currencies other than the

U.S. dollar. To prepare our consolidated financial statements, we must translate those assets, liabilities, revenues and expenses into U.S. dollars at then-applicable exchange rates. Consequently, increases and decreases in the value of the U.S. dollar versus other currencies will affect the amount of these items in our consolidated financial statements, even if the value has not changed in the original currency. These translations could result in changes to our results of operations from period to period. For the fiscal year ended December 31, 2007, approximately 15% of our revenues related to operations of our foreign subsidiaries whose functional currency is not the U.S. dollar.

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.

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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. For related discussion, see ITEM 1A. Risk Factors.

In general, production from EOG's natural gas and crude oil 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. For related discussion, see ITEM 1A. Risk Factors.

Acreage.

The following table summarizes EOG's developed and undeveloped acreage at December 31, 2007. 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	1,922,722	1,137,195	4,387,989	3,203,569	6,310,711	4,340,764
Canada	1,904,478	1,609,243	1,701,205	1,250,085	3,605,683	2,859,328
Trinidad	59,342	53,439	242,266	232,562	301,608	286,001
United Kingdom	10,230	2,946	410,676	176,766	420,906	179,712
Total	3,896,772	2,802,823	6,742,136	4,862,982	10,638,908	7,665,805

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, 2007. Gross natural gas and crude oil wells include 2,583 with multiple completions.

	Productive Wells	
	Gross	Net
Natural Gas	22,469	18,827
Crude Oil	1,704	1,115
Total	24,173	19,942

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Drilling and Acquisition Activities.

During the years ended December 31, 2007, 2006 and 2005, EOG expended $3,599 million, $2,927 million and $1,838 million, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of $31 million, $22 million and $20 million, respectively. EOG drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
United States and Canada						
Gas	1,747	1,441.6	2,240	1,921.5	1,523	1,241.3
Oil	98	85.8	60	49.9	79	68.6
Dry	59	51.5	66	57.2	80	70.0
Total	1,904	1,578.9	2,366	2,028.6	1,682	1,379.9
Outside United States and Canada						
Gas	6	4.7	1	0.3	2	0.6
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	6	4.7	1	0.3	2	0.6

Total Development	1,910	1,583.6	2,367	2,028.9	1,684	1,380.5
Exploratory Wells Completed						
United States and Canada						
Gas	62	53.4	53	44.8	61	47.0
Oil	14	12.1	2	1.8	3	2.6
Dry	18	16.2	21	17.0	23	17.5
Total	94	81.7	76	63.6	87	67.1
Outside United States and Canada						
Gas	-	-	2	1.8	-	-
Oil	-	-	-	-	-	-
Dry	2	1.4	-	-	3	0.7
Total	2	1.4	2	1.8	3	0.7
Total Exploratory	96	83.1	78	65.4	90	67.8
Total	2,006	1,666.7	2,445	2,094.3	1,774	1,448.3
Wells in Progress at end of period	223	195.7	221	180.9	160	123.9
Total	2,229	1,862.4	2,666	2,275.2	1,934	1,572.2
Wells Acquired(1)						
Gas	41	14.7	114	106.4	37	20.4
Oil	-	-	1	1.0	-	-
Total	41	14.7	115	107.4	37	20.4

(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 set forth under the "Contingencies" caption in Note 7 of Notes to Consolidated Financial Statements and is incorporated by reference herein.

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 2007.

PART II

ITEM 5. *Market for Registrant's Common Equity, Related Stockholder 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		Dividend Declared
	High	Low	
2007			
First Quarter	$73.09	$59.21	$ 0.09
Second Quarter	81.49	71.15	0.09
Third Quarter	76.92	65.29	0.09
Fourth Quarter	91.63	72.20	0.09
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

On January 31, 2007, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the previous $0.06 per share to $0.09 per share.

On February 7, 2008, the Board increased the quarterly cash dividend on the common stock from the previous $0.09 per share to $0.12 per share.

As of February 15, 2008, there were approximately 250 record holders of EOG's common stock, including individual participants in security position listings. There are an estimated 157,000 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 share 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, 2007 - October 31, 2007	9,117	$85.32	-	6,386,200
November 1, 2007 - November 30, 2007	2,585	87.29	-	6,386,200
December 1, 2007 - December 31, 2007	1,574	87.35	-	6,386,200
Total	13,276	85.94		

(1) The quarterly total number of shares of 13,276 consists solely of zero shares (15,558 shares for the full year 2007) that were returned to
EOG in payment of the exercise price of employee stock options and 13,276 shares (110,895 shares for the full year 2007) that were
withheld by or returned to EOG to satisfy tax withholding obligations that arose upon the exercise of employee stock options, stock-settled
stock appreciation rights 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 2007, EOG did not
repurchase any shares under the Board authorized repurchase program.

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Comparative Stock Performance

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

The performance graph shown below compares the cumulative five-year total return to stockholders on EOG's common stock as compared to the cumulative total returns on the Standard and Poor's 500 Index (S&P 500) and the Standard and Poor's 500 Oil & Gas Exploration & Production Index (S&P O&G E&P). The comparison was prepared based upon the following assumptions:

1. $100 was invested on December 31, 2002 in Common Stock of EOG, the S&P 500 and the S&P O&G E&P.
2. Dividends are reinvested.

Comparison of Five-Year Cumulative Total Returns

EOG, S&P 500 and S&P O&G E&P
(Performance Results Through December 31, 2007)

	2002	2003	2004	2005	2006	2007
EOG	$100.00	$116.19	$180.33	$371.95	$317.58	$455.88
S&P 500	$100.00	$126.38	$137.75	$141.88	$161.20	$166.89
S&P O&G E&P	$100.00	$123.64	$166.77	$277.51	$290.42	$419.44

ITEM 6. *Selected Financial Data*

(In Thousands, Except Per Share Data)

Year Ended December 31	2007	2006	2005	2004	2003
Statement of Income Data:					
Net Operating Revenues	$ 4,190,791	$ 3,912,542	$ 3,633,029	$ 2,277,178	$ 1,745,734
Operating Income	1,648,396	1,903,553	2,004,631	985,148	698,373
Net Income Before Cumulative Effect of Change in Accounting Principle	1,089,918	1,299,885	1,259,576	624,855	437,276
Cumulative Effect of Change in Accounting Principle, Net of Income Tax(1)	-	-	-	-	(7,131)
Net Income	1,089,918	1,299,885	1,259,576	624,855	430,145
Preferred Stock Dividends	6,663	10,995	7,432	10,892	11,032
Net Income Available to Common Stockholders	$ 1,083,255	$ 1,288,890	$ 1,252,144	$ 613,963	$ 419,113
Net Income Per Share Available to Common Stockholders(2)					
Basic					

Net Income Available to Common Stockholders Before Cumulative Effect of Change in Accounting Principle	$ 4.45	$ 5.33	$ 5.24	$ 2.63	$ 1.86
Cumulative Effect of Change in Accounting Principle, Net of Income Tax[1]	-	-	-	-	(0.03)
Net Income Per Share Available to Common Stockholders	$ 4.45	$ 5.33	$ 5.24	$ 2.63	$ 1.83
Diluted					
Net Income Available to Common Stockholders Before Cumulative Effect of Change in Accounting Principle	$ 4.37	$ 5.24	$ 5.13	$ 2.58	$ 1.83
Cumulative Effect of Change in Accounting Principle, Net of Income Tax[1]	-	-	-	-	(0.03)
Net Income Per Share Available to Common Stockholders	$ 4.37	$ 5.24	$ 5.13	$ 2.58	$ 1.80
Dividends Per Common Share[2]	$ 0.360	$ 0.240	$ 0.160	$ 0.120	$ 0.095
Average Number of Common Shares[2]					
Basic	243,469	241,782	238,797	233,751	229,194
Diluted	247,637	246,100	243,975	238,376	233,037

(1) EOG adopted Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003.
(2) Years 2003 and 2004 restated for two-for-one stock split effective March 1, 2005.

At December 31	2007	2006	2005	2004	2003
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 10,429,254	$ 7,944,047	$ 6,087,179	$ 5,101,603	$ 4,248,917
Total Assets	12,088,907	9,402,160	7,753,320	5,798,923	4,749,015
Current and Long-Term Debt	1,185,000	733,442	985,067	1,077,622	1,108,872
Stockholders' Equity	6,990,094	5,599,671	4,316,292	2,945,424	2,223,381

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

Overview

EOG Resources, Inc., together with its subsidiaries (collectively 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 stockholders for 2007 of $1,083 million was down 16% compared to 2006 net income available to common stockholders of $1,289 million. At December 31, 2007, EOG's total reserves were 7.7 trillion cubic feet equivalent, an increase of 944 billion cubic feet equivalent (Bcfe) from December 31, 2006.

Operations

Several important developments have occurred since January 1, 2007.

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 continues to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's natural gas and crude oil production. Production in the United States and Canada accounted for approximately 83% of total company production in 2007 as compared to 79% in 2006. Based on current trends, EOG expects its 2008 production profile to be similar. EOG's major producing areas are in Louisiana, New Mexico, Texas, Utah, Wyoming and western Canada.

In December 2007, EOG entered into an agreement to sell the majority of its producing shallow gas assets and surrounding acreage in the Appalachian Basin to a subsidiary of EXCO Resources, Inc., an independent oil and gas company, for approximately $395 million, subject to customary adjustments under the agreement. The Appalachian area being divested includes approximately 2,400 operated wells that accounted for approximately 1% of EOG's total 2007 production and approximately 2% of its total year-end 2007 proved reserves. The transaction closed on February 20, 2008. EOG retained certain of its undeveloped acreage in this area, including rights in the Marcellus Shale, and will continue its shale exploration program. On December 31, 2007, the book value of the assets and liabilities included in the sale were $254 million and $9 million, respectively.

International.

Although EOG continues to focus on United States and Canada natural gas, EOG continues to see linkage between United States and Canada natural gas demand and Trinidad natural gas supply. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Under the Atlantic LNG Train 4 (ALNG) contract, EOG delivered gas at the contractual rate of 30 million cubic feet per day (MMcfd), gross (12 MMcfd, net) beginning in May 2007 when the ALNG plant reached commercial status. In March 2007, EOG acquired the remaining 10% working interest from Primera Block 4(a) Limited, a Trinidadian company, and now holds a 100% working interest in Block 4(a). In July 2007, EOG executed a 15-year natural gas contract with the National Gas Company of Trinidad and Tobago (NGC) for the sale of approximately 100 MMcfd, gross (78 MMcfd, net to EOG, based on current pricing and operating assumptions). EOG expects to begin initial delivery under this contract in early 2010 from its first discovery on Block 4(a), subject to the completion of a pipeline by NGC.

In May 2007, EOG acquired the remainder of the interest in the Modified U(b) Block from Primera Oil & Gas Ltd., a Trinidadian company, and now holds a 100% working interest in the Modified U(b) Block. In August 2007, EOG drilled the U(b)-2 exploratory well on the Modified U(b) Block, and the well was determined to be non-commercial. In 2007, EOG agreed to purchase an 80% interest in the Pelican field facilities from the subsidiaries of the other participants in the South East Coast Consortium Block. The transaction is expected to close in the first quarter of 2008.

During 2007, EOG executed a one-year term sheet, effective July 1, 2007, with the Petroleum Company of Trinidad and Tobago that sets forth the pricing for the sales of crude oil and condensate produced in Trinidad. The pricing terms are based on the valuation of the distillation yield of the crude oil and condensate produced less a refining margin. This term sheet replaces the pricing provisions of a previous crude oil and condensate sales contract

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that expired on June 30, 2007 and will be incorporated into a new crude oil and condensate sales contract which is expected to be finalized in the first quarter of 2008.

In addition to EOG's ongoing production from the Valkyrie and Arthur Fields in the United Kingdom North Sea, EOG participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f, at the end of 2006. In 2007, a successful appraisal well was drilled on this prospect. The future development of this prospect is currently being evaluated. EOG also participated in the drilling of an unsuccessful exploratory well in August 2007 on the Eos prospect located in the Southern North Sea Block 45/11c.

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.

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, 2007, EOG's debt-to-total capitalization ratio was 14%, up from 12% at year-end 2006. By primarily utilizing cash on hand, cash provided from its operating activities and proceeds from long-term debt borrowings, EOG funded $3.9 billion in exploration and development and other property, plant and equipment expenditures, paid down $158 million of debt, paid dividends to common and preferred stockholders of $84 million and paid $51 million for the redemption of preferred stock. As management continues to assess price forecast and demand trends for 2008, EOG believes that operations and capital expenditure activity can be largely funded by cash from operations.

For 2008, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $4.4 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 10, 2007, EOG completed its public offering of $600 million aggregate principal amount of 5.875% Senior Notes due 2017 (2017 Notes). Interest on the 2017 Notes is payable semi-annually on March 15 and September 15 of each year, beginning March 15, 2008. Net proceeds from the offering were approximately $595 million and were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

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/or common stock. The New Registration Statement was filed to replace EOG's then existing shelf registration statement which had been declared effective by the Securities and Exchange Commission (SEC) in October 2000 and under which EOG had sold no securities. As of December 31, 2007, and as a result of the issuance of the 2017 Notes, EOG may offer and sell up to $88,237,500 of debt securities, preferred stock and/or common stock under the New Registration Statement.

In 2007, EOG repurchased a total of 48,260 shares of its outstanding 7.195% Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, with a $1,000 liquidation preference per share (Series B), for an aggregate purchase price, including premium and fees, of $51 million, plus accrued dividends up to the date of repurchase. EOG has included as a component of preferred stock dividends the $3 million of premium and fees associated with the repurchases. At December 31, 2007, 5,000 shares of the Series B with a book value of $5 million remained outstanding. Such remaining shares were subsequently repurchased in January 2008. See Note 3 to Consolidated Financial Statements.

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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. Stock-based compensation expense is included in the Consolidated Statements of Income and Comprehensive Income based upon job functions of employees receiving the grants. EOG compensation expense related to its stock-based compensation plans for the years ended December 31, was as follows (in millions):

	2007	2006	2005
Lease and Well	$ 14	$ 10	$ -
Exploration Costs	13	11	-
General and Administrative	40	29	12
Total	$ 67	$ 50	$ 12

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Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2007 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2007, net operating revenues increased $278 million, or 7%, to $4,191 million from $3,913 million in 2006. Total wellhead revenues, which are revenues generated from sales of natural gas, crude oil, condensate and natural gas liquids, increased $474 million, or 13%, to $4,039 million from $3,565 million in 2006. Wellhead volume and price statistics for the years ended December 31, were as follows:

	2007	2006	2005
Natural Gas Volumes (MMcfd)			
United States	971	817	718
Canada	224	226	228
Trinidad	252	264	231
United Kingdom	23	30	39

Total	1,470	1,337	1,216
Average Natural Gas Prices ($/Mcf) (1)			
United States	$ 6.32	$ 6.56	$ 7.86
Canada	6.25	6.41	7.14
Trinidad	2.71	2.44	2.20
United Kingdom	6.19	7.69	6.99
Composite	5.69	5.74	6.62
Crude Oil and Condensate Volumes (MBbld) (2)			
United States	24.6	20.7	21.5
Canada	2.4	2.5	2.4
Trinidad	4.1	4.8	4.5
United Kingdom	0.1	0.1	0.2
Total	31.2	28.1	28.6
Average Crude Oil and Condensate Prices ($/Bbl) (1)			
United States	$68.85	$62.68	$54.57
Canada	65.27	57.32	50.49
Trinidad	69.84	63.87	57.36
United Kingdom	66.84	57.74	49.62
Composite	68.69	62.38	54.63
Natural Gas Liquids Volumes (MBbld) (2)			
United States	11.1	8.5	6.6
Canada	1.1	0.8	0.9
Total	12.2	9.3	7.5

Average Natural Gas Liquids Prices ($/Bbl) [1]			
United States	$47.63	$39.95	$35.59
Canada	44.54	43.69	35.59
Composite	47.36	40.25	35.59
Natural Gas Equivalent Volumes (MMcfed) [3]			
United States	1,184	992	886
Canada	245	246	248
Trinidad	276	292	259
United Kingdom	24	31	40
Total	1,729	1,561	1,433
Total Bcfe [3] Deliveries	631.3	569.9	523.0

(1) Dollars per thousand cubic feet or per barrel, as applicable.
(2) Thousand barrels per day.
(3) Million cubic feet equivalent per day; 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.

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J007 compared to 2006.

Wellhead natural gas revenues for 2007 increased $248 million, or 9%, to $3,051 million from $2,803 million for 2006 due to increased natural gas deliveries ($278 million), partially offset by a lower composite average wellhead natural gas price ($30 million). The composite average wellhead natural gas price decreased to $5.69 per Mcf for 2007 from $5.74 per Mcf in 2006.

Natural gas deliveries increased 133 MMcfd, or 10%, to 1,470 MMcfd for 2007 from 1,337 MMcfd in 2006. The increase was due to higher production of 154 MMcfd in the United States, partially offset by lower production of 12 MMcfd in Trinidad, 7 MMcfd in the United Kingdom and 2 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (119 MMcfd), the Rocky Mountain area (13 MMcfd), Kansas (13 MMcfd) and Mississippi (10 MMcfd). The decline in Trinidad was due to reduced 2007 deliveries to ALNG (10 MMcfd) and a decrease in contractual demand (2 MMcfd). During 2006, EOG supplied gas for use in ALNG's start-up phase. In 2007, ALNG remained in the start-up phase, but did not require any gas from EOG until May 2007 when ALNG reached commercial status and EOG began supplying gas under the ALNG take-or-pay contract. 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 $153 million, or 24%, to $778 million from $625 million as compared to 2006, due to an increase in wellhead crude oil and condensate deliveries ($81 million) and a higher composite average wellhead crude oil and condensate price ($72 million). The increase in deliveries primarily reflects increased production in North Dakota. The composite average wellhead crude oil and condensate price for 2007 was $68.69 per barrel compared to $62.38 per barrel for 2006.

Natural gas liquids revenues increased $73 million, or 53%, to $210 million from $137 million as compared to 2006, due to increases in deliveries ($42 million) and the composite average price ($31 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale and South Texas areas.

During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included realized gains of $128 million. During 2006, EOG recognized gains on mark-to-market financial commodity derivative contracts of $334 million, which included realized gains of $215 million.

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).

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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.

Operating and Other Expenses

2007 compared to 2006. During 2007, operating expenses of $2,542 million were $533 million higher than the $2,009 million incurred in 2006. The following table presents the costs per Mcfe for the years ended December 31:

	2007	**2006**
Lease and Well	$0.76	$0.66
Transportation Costs	0.27	0.19
Depreciation, Depletion and Amortization (DD&A)	1.69	1.44
General and Administrative (G&A)	0.33	0.29
Net Interest Expense	0.07	0.08
Total Per-Unit Costs (1)	$3.12	$2.66

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

The primary factors impacting per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2007 as compared to 2006 are 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 $480 million in 2007 were $107 million higher than 2006 due primarily to higher operating and maintenance expenses in the United States ($62 million) and Canada ($13 million), higher lease and well administrative expenses ($18 million), higher workover expenditures in the United States ($7 million) and changes in the Canadian exchange rate ($7 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 (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees, fuel costs and transportation fees.

Transportation costs of $170 million in 2007 were $60 million higher than 2006 due primarily to increased production in the Fort Worth Basin Barnett Shale play and related costs associated with new marketing arrangements to transport the increased production to new downstream markets.

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.

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DD&A expenses of $1,066 million in 2007 were $248 million higher than 2006 primarily due to higher unit rates described below and as a result of increased production in the United States ($122 million), partially offset by a decrease in production in the United Kingdom ($5 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($102 million), Canada ($17 million) and in the United Kingdom ($2 million). The exchange rates in Canada ($10 million) and in the United Kingdom ($2 million) also contributed to the DD&A expense increase.

G&A expenses of $205 million in 2007 were $40 million higher than 2006 due primarily to higher employee-related costs ($24 million), legal settlement costs ($4 million), insurance costs ($3 million) and office rent ($2 million). The increase in employee-related costs primarily reflects higher stock-based compensation expenses ($11 million).

Net interest expense of $47 million in 2007 increased $4 million compared to 2006 primarily due to a higher average debt balance ($13 million), partially offset by higher capitalized interest ($9 million).

Exploration costs of $150 million in 2007 were $5 million lower than 2006 due primarily to decreased geological and geophysical expenditures in the United States.

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 $148 million in 2007 were $39 million higher than 2006 due primarily to increased SFAS No. 144 related impairments ($27 million) and increased amortization of unproved leases in the United States ($7 million), the United Kingdom ($3 million) and Canada ($3 million). The increase in SFAS No. 144 related impairments is due to an increase in Canada ($15 million) primarily related to the Northwest Territories discovery (see Note 15 to Consolidated Financial Statements) and an increase in the United States ($12 million). Under SFAS No. 144, EOG recorded impairments of $82 million and $55 million for 2007 and 2006, respectively.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are determined based on wellhead revenue and ad valorem/property taxes are generally determined based on the valuation of the underlying assets. Taxes other than income in 2007 increased $7 million to $208 million (5.2% of wellhead revenues) from $201 million (5.6% of wellhead revenues) in 2006.

Severance/production taxes increased primarily due to increased wellhead revenues in the United States ($27 million) and Trinidad ($2 million), partially offset by increased credits taken for Texas high cost gas severance tax rate reductions ($26 million). Ad valorem/property taxes increased primarily due to higher property valuation in Canada ($2 million).

Other income, net was $29 million in 2007 compared to $52 million in 2006. The decrease of $23 million was primarily due to lower interest income ($17 million), lower settlements received related to the Enron Corp. bankruptcy ($3 million) and lower equity income from the Nitrogen (2000) Unlimited ammonia plant ($2 million).

Income tax provision of $541 million in 2007 decreased $72 million compared to 2006 due primarily to decreased pretax income ($99 million), partially offset by higher foreign income taxes ($10 million) and increased state income taxes ($7 million). The net effective tax rate for 2007 increased to 33% from 32% in 2006.

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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:

	2007	**2006**
Lease and Well	$0.66	$0.54
Transportation Costs	0.19	0.17
DD&A	1.44	1.25
G&A	0.29	0.24
Net Interest Expense	0.08	0.12
Total Per-Unit Costs (1)	$2.66	$2.32

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

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

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 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 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).

Net interest expense of $43 million in 2006 decreased $19 million compared to 2005 primarily due to a 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 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.

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).

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Other income, net was $52 million in 2006 compared to $23 million in 2005. The increase of $29 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).

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.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2007 were funds generated from operations, the issuance of long-term debt, proceeds from employee stock option exercises and the employee stock purchase plans, proceeds from the sale of oil and gas properties, excess tax benefits from stock-based compensation, net commercial paper, other uncommitted credit facilities and revolving credit facility borrowings. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; repayments of debt; dividend payments to stockholders; redemptions of preferred stock and debt issuance costs.

2007 compared to 2006. Net cash provided by operating activities of $2,893 million in 2007 increased $315 million compared to 2006 primarily reflecting an increase in wellhead revenues ($474 million) and a decrease in cash paid for income taxes ($157 million), partially offset by an increase in cash operating expenses ($180 million), a decrease in the net cash flows from settlement of financial commodity derivative contracts ($87 million) and unfavorable changes in working capital and other assets and liabilities ($55 million).

Net cash used in investing activities of $3,456 million in 2007 increased by $745 million compared to 2006 due primarily to increased additions to oil and gas properties and other property, plant and equipment.

Net cash provided by financing activities was $394 million in 2007 compared to net cash used in financing activities of $299 million in 2006. Cash provided by financing activities for 2007 included the issuance of long-term debt ($600 million), proceeds from employee stock option exercises and employee stock purchase plans ($55 million), excess tax benefits from stock-based compensation ($27 million) and Trinidad revolving credit facility borrowings ($10 million). Cash used by financing activities for 2007 included repayments of long-term borrowings ($158 million), cash dividend payments ($84 million), redemptions of preferred stock ($51 million) and debt issuance costs ($5 million).

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),

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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).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2007, 2006 and 2005, along with the total budgeted for 2008, excluding acquisitions (in millions):

	Actual			Budgeted
	2007	2006	2005	2008 (excluding acquisitions)
Expenditure Category				
Capital				
Drilling and Facilities	$2,976	$2,403	$1,418	
Leasehold Acquisitions	278	225	131	
Producing Property Acquisitions	20	22	56	
Capitalized Interest	29	20	15	
Subtotal	3,303	2,670	1,620	
Exploration Costs	150	155	133	
Dry Hole Costs	115	80	65	
Exploration and Development Expenditures	3,568	2,905	1,818	Approximately $4,100
Asset	31	22	20	

Retirement Costs				
Total Exploration and Development Expenditures	3,599	2,927	1,838	
Other Property, Plant and Equipment	277	100	63	Approximately $280
Total Expenditures	$3,876	$3,027	$1,901	

Exploration and development expenditures of $3,568 million for 2007 were $663 million higher than the prior year due primarily to increased drilling and facilities expenditures of $573 million resulting from higher drilling and facilities expenditures in the United States ($648 million); increased lease acquisitions in the United States ($57 million); increased dry hole costs in the United States ($19 million), Trinidad ($9 million) and the United Kingdom ($7 million); changes in the Canadian exchange rate ($18 million); and increased capitalized interest in the United States ($8 million). These increases were partially offset by lower drilling and facilities expenditures in Canada ($70 million), the United Kingdom ($12 million) and Trinidad ($7 million); decreased geological and geophysical expenditures in the United States ($7 million); and decreased lease acquisitions in the United Kingdom ($6 million). The 2007 exploration and development expenditures of $3,568 million includes $2,681 million in development, $838 million in exploration, $29 million in capitalized interest and $20 million in property acquisitions. The increase in expenditures for other property, plant and equipment primarily related to gathering systems and processing plants in the Fort Worth Basin Barnett Shale and Rocky Mountain areas. The 2006 exploration and development expenditures of $2,905 million includes $2,159 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 $1,818 million includes $1,260 million in development, $487 million in exploration, $56 million in property acquisitions and $15 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 North Sea, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included realized gains of $128 million. During 2006, EOG recognized gains on mark-to-market financial commodity derivative contracts of $334 million, which included realized gains of $215 million. See Note 11 to Consolidated Financial Statements.

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Presented below is a comprehensive summary of EOG's 2008 and 2009 natural gas and crude oil financial price swap contracts at February 27, 2008, with notional volumes in million British thermal units per day (MMBtud) and in barrels per day (Bbld), as applicable, and prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), 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	
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
2008				
January (closed)	385,000	$8.92	-	$ -
February [(1)]	420,000	8.88	6,000	90.86
March	455,000	8.64	10,000	91.02
April	455,000	8.11	14,000	92.20
May	455,000	8.10	14,000	92.20
June	455,000	8.18	14,000	92.20
July	455,000	8.26	14,000	92.20
August	455,000	8.33	14,000	92.20
September	455,000	8.36	14,000	92.20
October	455,000	8.44	14,000	92.20
November	455,000	8.83	14,000	92.20
December	455,000	9.23	4,000	91.96
2009				
January	350,000	$9.36	-	-
February	350,000	9.36	-	-
March	350,000	9.13	-	-
April	350,000	8.22	-	-
May	350,000	8.19	-	-
June	350,000	8.25	-	-
July	350,000	8.32	-	-
August	350,000	8.37	-	-
September	350,000	8.38	-	-
October	350,000	8.44	-	-
November	350,000	8.67	-	-
December	350,000	8.95	-	-

(1) The natural gas contracts for February 2008 are closed. The crude oil contracts for February 2008 will close on February 29, 2008.

Financing

EOG's debt-to-total capitalization ratio was 14% at December 31, 2007 compared to 12% at December 31, 2006.

During 2007, total debt increased $452 million to $1,185 million (see Note 2 to Consolidated Financial Statements). The estimated fair value of EOG's debt at December 31, 2007 and 2006 was $1,227 million and $754 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, 2007, a 1% decline in interest rates would result in an $83 million increase in the estimated fair value of the fixed rate obligations (see Note 11 to Consolidated Financial Statements).

During 2007 and 2006, EOG utilized cash provided by operating activities, net commercial paper and other uncommitted credit facilities and revolving credit facility borrowings to fund its capital programs. While EOG maintains a $1.0 billion commercial paper program, the maximum outstanding at any time during 2007 was $590 million, and the amount outstanding at year-end was zero. The maximum amount outstanding under uncommitted

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credit facilities during 2007 was $123 million with no amounts outstanding at year-end. EOG considers this excess availability, which is backed by the $1.0 billion Revolving Credit Agreement with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, combined with approximately $88 million of availability under its shelf registration described below, to be ample to meet its ongoing operating needs.

During September 2007, EOG issued $600 million aggregate principal amount of its 2017 Notes. Net proceeds of approximately $595 million were used for general corporate purposes including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities. In December 2007, EOG repaid, at maturity, the remaining $98 million principal amount of its 6.50% Notes due in 2007. Also during 2007, a foreign subsidiary of EOG repaid the remaining $60 million year-end 2006 outstanding balance of its $600 million, 3-year unsecured Senior Term Loan Agreement. EOG had previously terminated its remaining borrowing capacity under the Senior Term Loan Agreement.

In 2007, EOG repurchased a total of 48,260 shares of its outstanding Series B for an aggregate purchase price, including premium and fees, of $51 million, plus accrued dividends up to the date of repurchase. EOG has included as a component of preferred stock dividends the $3 million of premium and fees associated with the repurchases. At December 31, 2007, 5,000 shares of the Series B with a book value of $5 million remained outstanding. Such remaining shares were subsequently repurchased in January 2008.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2007 (in thousands):

Contractual Obligations (1)	Total	2008	2009 - 2010	2011 - 2012	2013 & Beyond
Long-Term Debt	$1,185,000	$ -	$ 75,000	$220,000	$ 890,000
Non-Cancelable Operating Leases	211,654	28,472	42,305	33,881	106,996
Interest Payments on Long-Term Debt	656,628	71,105	135,510	118,770	331,243
Pipeline					

Transportation Service Commitments (2)	1,928,603	149,495	385,862	377,473	1,015,773
Drilling Rig Commitments (3)	380,004	200,878	178,291	835	-
Seismic Purchase Obligations	3,027	3,027	-	-	-
Other Purchase Obligations	30,767	30,767	-	-	-
Total Contractual Obligations	$4,395,683	$483,744	$816,968	$750,959	$2,344,012

(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, 2007. 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.

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities or partnerships, 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 limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions or any other "off-balance sheet arrangement" (as defined in Item 303(a)(4) of Regulation S-K) during any of the periods in this report, and currently has no intention of participating in any such transaction or arrangement in the foreseeable future.

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Foreign Currency Exchange Rate Risk

During 2007, 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 2007 was the Canadian Dollar. The fluctuation of the Canadian Dollar in 2007 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, 2007, EOG recorded the fair value of the swap of $58 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 Stockholders on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap transaction resulted in a positive change of $8 million for the year ended December 31, 2007. The change is included in Accumulated Other Comprehensive Income in the Stockholders' Equity section of the Consolidated Balance Sheets.

Outlook

Pricing. 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. The market price of natural gas and crude oil and condensate in 2008 will impact the level of EOG's 2008 total capital expenditures as well as its production.

Including the impact of EOG's 2008 natural gas and crude oil hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2008 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 $20 million for net income and operating cash flow. EOG's price sensitivity in 2008 for each $1.00 per barrel change in wellhead crude oil price, combined with the related change in natural gas liquids prices, is approximately $10 million for net income and operating cash flow. For information regarding EOG's natural gas and crude oil hedge position as of December 31, 2007, see Note 11 to Consolidated Financial Statements.

Capital.

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. In 2008, EOG expects to allocate an increased amount of its domestic exploration and development expenditures to the Fort Worth Basin Barnett Shale and the Rocky Mountain operating area which includes the Uinta Basin and the North Dakota Bakken. In order to diversify its overall asset portfolio, EOG anticipates continuing to expend a portion of its available funds in the further development of Trinidad and the United Kingdom North Sea. 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 2008 exploration and development expenditures, excluding acquisitions, are approximately $4.1 billion. In addition, budgeted 2008 expenditures for natural gas gathering and processing and other assets are approximately $280 million. The total 2008 capital expenditures budget of $4.4 billion, excluding acquisitions, is 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 total capital expenditures may vary in 2008 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, proceeds from asset sales and available financing alternatives in 2008 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

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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.

Operations.

Based on average North American natural gas prices of $7.50 per Mcf at Henry Hub and a total budget for exploration and development expenditures of $4.1 billion, excluding acquisitions, EOG expects to increase overall production in 2008 by 15% over 2007 levels. United States production is expected to increase by 19%, with a planned increase in crude oil and condensate and natural gas liquids production of 36% and 40%, respectively.

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 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 cleanup 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 national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. We are also aware of legislation, recently proposed by the Canadian legislature, to reduce GHG emissions. Additionally, proposed United States policy, legislation or regulatory actions may also address GHG emissions. EOG will continue to monitor and assess any new policies, legislation or regulations in the areas where we are operating to determine the impact on our operations and take appropriate actions, where necessary.

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.

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Oil and Gas Exploration Costs

EOG accounts for its natural gas and crude oil exploration and production activities under the successful efforts method of accounting. 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, 2007 and 2006, 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 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 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 depreciation, depletion and 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." 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.

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, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 or 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 the expectations reflected in its 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 EOG's 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, interest rates and financial market conditions;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and impact of liquefied natural gas imports;
- changes in demand or prices for ammonia or methanol;
- 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 ability to achieve production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reservoir performance;
- the availability and cost of drilling rigs, experienced drilling crews, tubular steel and other materials, equipment and services used in drilling and well completions;
- the availability, terms and timing of mineral licenses and leases and governmental and other permits and rights of way;
- access to surface locations for drilling and production facilities;
- the availability and capacity of gathering, processing and pipeline transportation facilities;
- 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 and the enactment of new government policies, legislation and regulations, including environmental regulations;
- acts of war and terrorism and responses to these acts; and
- weather, including weather-related delays in the installation of gathering and production facilities.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur. EOG's 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.

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

The information required by this Item is incorporated by reference from Item 7 of this report, specifically the information set forth under the captions "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. *Financial Statements and Supplementary Data*

The information required by this Item is included in this report as set forth in the "Index to Financial Statements" on page F-1 and is incorporated by reference herein.

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 December 31, 2007. Based on this evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of December 31, 2007 in ensuring 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 Annual 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) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2007. 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 and such criteria, EOG's management believes that EOG's internal control over financial reporting was effective as of

December 31, 2007. See also "Management's Responsibility for Financial Reporting" appearing on page F-2 of this report, which is incorporated herein by reference.

The report of EOG's independent registered public accounting firm relating to the consolidated financial statements, financial statement schedules and effectiveness of internal control over financial reporting is set forth on page F-3 of this report.

There were no changes in EOG's internal control over financial reporting that occurred during the quarter ended December 31, 2007 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*

The information required by this Item is incorporated by reference from (i) the Definitive Proxy Statement to be filed not later than April 29, 2008, specifically the information to be set forth therein under the captions "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance," and (ii) Item 1 of this report, specifically the information therein set forth under the caption "Executive Officers of the Registrant."

Pursuant to Rule 303A.10 of the New York Stock Exchange and Item 406 of Regulation S-K promulgated under the Exchange Act, EOG has adopted a Code of Business Conduct and Ethics (Code of Conduct) that applies to all EOG directors, officers and employees, including EOG's principal executive officer and principal financial and accounting officer.

You can access the Code of Conduct on the Corporate Governance page under Investors on EOG's website at www.eogresources.com, and any EOG stockholder who so requests may obtain a printed copy of the Code of Conduct by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose amendments to the Code of Conduct, and waivers with respect to the Code of Conduct granted to EOG's principal executive officer and principal financial and accounting officer, on its website at www.eogresources.com within four business days of the amendment or waiver. In such case, the disclosure regarding the amendment or waiver will remain available on EOG's website for at least 12 months after the initial disclosure.

ITEM 11. *Executive Compensation*

The information required by this Item is incorporated by reference from the Definitive Proxy Statement to be filed not later than April 29, 2008, specifically the information to be set forth therein under the captions "Executive Compensation," "Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report." The Compensation Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that EOG specifically incorporates such information by reference into such a filing.

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 Definitive Proxy Statement to be filed not later than April 29, 2008, specifically the information to be set forth therein under the caption "Voting Rights and Principal Stockholders."

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Equity Compensation Plan Information

EOG Resources, Inc. (EOG) has various plans under which employees and nonemployee members of the Board of Directors (Board) of EOG have been or may be granted certain equity compensation consisting of stock options, stock appreciation rights, 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, 2007.

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	9,241,133	$51.01	1,222,347 (1) (2)
Equity Compensation Plans Not Approved by Security Holders	3,199,743	$21.06	151,527 (3) (4)
Total	12,440,876	$43.30	1, 373,874

(1) Of these securities, 213,286 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 971,061 could be issued as restricted stock or restricted stock units under the 1992 Stock Plan.
(3) Of these securities, 27,663 phantom stock units remain available for issuance under the 1996 Deferral Plan.
(4) Of these securities, 123,864 could be issued as restricted stock or restricted stock units under the 1994 Stock Plan.

Stock Plan Not Approved by Security Holders.

The Board 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 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 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 up to five years after the date of grant 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 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. At December 31, 2007, 92,337 phantom stock units had been issued.

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

The information required by this Item is incorporated by reference from the Definitive Proxy Statement to be filed not later than April 29, 2008, specifically the information to be set forth therein under the captions "Related Party Transactions" and "Corporate Governance."

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ITEM 14. *Principal Accounting Fees and Services*

The information required by this Item is incorporated by reference from the Definitive Proxy Statement to be filed not later than April 29, 2008, specifically the information to be set forth therein under the caption "Item 2 - Ratification of Appointment of Auditors - General."

PART IV

ITEM 15. *Exhibits, 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), (b) Exhibits

See pages E-1 through E-5 for a listing of the exhibits.

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EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

Financial Statement Schedule:

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., together with its subsidiaries (collectively EOG), were prepared by management, which is responsible for the integrity, objectivity and fair presentation of such financial statements. 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 as conditions change.

The adequacy of EOG's financial controls and the accounting principles employed by EOG in its financial reporting 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. Moreover, EOG's 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, 2007. 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 and those criteria, management believes that EOG maintained effective internal control over financial reporting as of December 31, 2007.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements of EOG 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 stockholders, 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 EOG's system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on EOG's consolidated financial statements and the effectiveness of EOG's internal control over financial reporting. Their report begins on page F-3.

MARK G. PAPA	TIMOTHY K. DRIGGERS
Chairman of the Board and	Vice President and Chief
Chief Executive Officer	Financial Officer

Houston, Texas
February 28, 2008

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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, 2007 and 2006, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December

31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2007, 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, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on 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 audits of the 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included 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 generally accepted accounting principles. 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 generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the EOG Resources, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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 1 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 28, 2008

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

Year Ended December 31	2007	2006	2005
Net Operating Revenues			
Natural Gas	$3,050,973	$2,803,245	$2,938,917
Crude Oil, Condensate and Natural Gas Liquids	987,523	761,580	668,073
Gains on Mark-to-Market Commodity Derivative Contracts	93,108	334,260	10,475
Other, Net	59,187	13,457	15,564
Total	4,190,791	3,912,542	3,633,029
Operating Expenses			
Lease and Well	479,819	372,895	286,417
Transportation Costs	170,404	110,328	86,938
	150,445	155,008	133,116

Exploration Costs			
Dry Hole Costs	115,382	79,567	64,812
Impairments	147,517	108,258	77,932
Depreciation, Depletion and Amortization	1,065,545	817,089	654,258
General and Administrative	205,210	164,981	125,918
Taxes Other Than Income	208,073	200,863	199,007
Total	2,542,395	2,008,989	1,628,398
Operating Income	1,648,396	1,903,553	2,004,631
Other Income, Net	29,250	52,246	23,012
Income Before Interest Expense and Income Taxes	1,677,646	1,955,799	2,027,643
Interest Expense			
Incurred	76,102	63,058	77,102
Capitalized	(29,324)	(19,900)	(14,596)
Net Interest Expense	46,778	43,158	62,506
Income Before Income Taxes	1,630,868	1,912,641	1,965,137
Income Tax Provision	540,950	612,756	705,561
Net Income	1,089,918	1,299,885	1,259,576
Preferred Stock Dividends	6,663	10,995	7,432
Net Income Available	$1,083,255	$1,288,890	$1,252,144

to Common Stockholders			
Net Income Per Share Available to Common Stockholders			
Basic	$ 4.45	$ 5.33	$ 5.24
Diluted	$ 4.37	$ 5.24	$ 5.13
Average Number of Common Shares			
Basic	243,469	241,782	238,797
Diluted	247,637	246,100	243,975
Comprehensive Income			
Net Income	$1,089,918	$1,299,885	$1,259,576
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	282,619	883	34,074
Foreign Currency Swap Transaction	10,789	(219)	(7,567)
Income Tax Related to Foreign Currency Swap Transaction	(3,086)	(605)	2,615
Defined Benefit Pension and Post-Retirement Plans	(595)	-	-

Income Tax Related to Defined Benefit Pension and Post-Retirement Plans	271	-	-
Comprehensive Income	$1,379,916	$1,299,944	$1,288,698

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	2007	2006
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 54,231	$ 218,255
Accounts Receivable, Net	835,670	754,134
Inventories	102,322	113,591
Assets from Price Risk Management Activities	100,912	130,612
Income Taxes Receivable	110,370	94,311
Deferred Income Taxes	33,533	-
Other	55,001	39,177
Total	1,292,039	1,350,080
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	16,981,836	13,575,528
Other Property, Plant	581,402	318,323

and Equipment		
	17,563,238	13,893,851
Less: Accumulated Depreciation, Depletion and Amortization	(7,133,984)	(5,949,804)
Total Property, Plant and Equipment, Net	10,429,254	7,944,047
Long-Term Assets Held for Sale	254,376	-
Other Assets	113,238	108,033
Total Assets	$ 12,088,907	$ 9,402,160

LIABILITIES AND STOCKHOLDERS' EQUITY

Current Liabilities		
Accounts Payable	$ 1,152,140	$ 896,572
Accrued Taxes Payable	104,647	130,984
Dividends Payable	22,045	14,718
Liabilities from Price Risk Management Activities	3,404	-
Deferred Income Taxes	108,980	144,615
Other	82,954	68,123
Total	1,474,170	1,255,012
Long-Term Debt	1,185,000	733,442
Other Liabilities	368,336	300,907
Deferred Income Taxes	2,071,307	1,513,128
Stockholders' Equity		
Preferred Stock, $0.01 Par, 10,000,000		

Shares Authorized:		
Series B, Cumulative, $1,000 Liquidation Preference Per Share, 5,000 Shares Outstanding at December 31, 2007, and 53,260 Shares Outstanding at December 31, 2006	4,977	52,887
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 249,460,000 Shares Issued	202,495	202,495
Additional Paid in Capital	221,102	129,986
Accumulated Other Comprehensive Income	466,702	176,704
Retained Earnings	6,156,721	5,151,034
Common Stock Held in Treasury, 2,935,313 Shares at December 31, 2007 and 5,724,959 Shares at December 31, 2006	(61,903)	(113,435)
Total Stockholders' Equity	6,990,094	5,599,671
Total Liabilities and Stockholders'	$ 12,088,907	$ 9,402,160

Equity

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

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EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' 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 Stockholders' Equity
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, Net of Tax	-	-	-	-	(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 No. 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, Net of Tax	-	-	-	-	(824)	-	-	(824)
Treasury Stock Issued Under Stock Plans	-	-	9,623	-	-	-	8,945	18,568
Tax Benefits from Stock-Based Compensation	-	-	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 No. 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
Net Income	-	-	-	-	-	1,089,918	-	1,089,918
Redemption of Preferred Stock	(48,260)	-	-	-	-	-	-	(48,260)
Amortization of Preferred Stock Discount	350	-	-	-	-	(350)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(6,313)	-	(6,313)
Common Stock Dividends Declared, $0.36 Per Share	-	-	-	-	-	(88,368)	-	(88,368)
Translation Adjustment	-	-	-	-	282,619	-	-	282,619
Foreign Currency Swap Transaction, Net of Tax	-	-	-	-	7,703	-	-	7,703
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	-	(324)	-	-	(324)
Treasury Stock Issued Under Stock Plans	-	-	16,205	-	-	-	30,106	46,311
Tax Benefits from Stock-Based Compensation	-	-	29,084	-	-	-	-	29,084
Restricted Stock and Units	-	-	(21,426)	-	-	-	21,426	-
Expense on Stock-Based Compensation	-	-	67,253	-	-	-	-	67,253

Retained Earnings Reclass for FASB Interpretation No. 48	-	-	-	-	-	10,800	-	10,800
Balance at December 31, 2007	$ 4,977	$202,495	$221,102	$ -	$466,702	$6,156,721	$ (61,903)	$6,990,094

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	2007	2006	2005
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 1,089,918	$ 1,299,885	$ 1,259,576
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	1,065,545	817,089	654,258
Impairments	147,517	108,258	77,932
Stock-Based Compensation Expenses	67,253	49,875	12,187
Deferred Income Taxes	426,827	385,842	270,291
Other, Net	(44,138)	(18,404)	(17,859)
Dry Hole Costs	115,382	79,567	64,812
Mark-to-Market Commodity Derivative Contracts			
Total Gains	(93,108)	(334,260)	(10,475)

Realized Gains	127,969	215,063	9,807
Tax Benefits from Stock Options Exercised	-	-	50,880
Other, Net	24,268	20,670	10,228
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(85,024)	9,905	(315,557)
Inventories	9,638	(50,370)	(23,085)
Accounts Payable	228,354	222,012	248,411
Accrued Taxes Payable	(40,002)	(106,324)	88,151
Other Assets	(8,416)	13,060	(16,539)
Other Liabilities	4,976	(9,477)	4,979
Changes in Components of Working Capital Associated with Investing and Financing Activities	(143,594)	(123,838)	1,429
Net Cash Provided by Operating Activities	2,893,365	2,578,553	2,369,426
Investing Cash Flows			
Additions to Oil and Gas Properties	(3,401,986)	(2,750,262)	(1,685,297)
Additions to Other Property, Plant and Equipment	(277,076)	(99,861)	(62,724)
Proceeds from Sales of Assets	83,295	20,041	70,987
Changes in Components of Working Capital			

Associated with Investing Activities	143,668	123,890	(1,538)
Other, Net	(3,675)	(4,181)	464
Net Cash Used in Investing Activities	(3,455,774)	(2,710,373)	(1,678,108)
Financing Cash Flows			
Net Commercial Paper and Revolving Credit Facility Borrowings (Repayments)	10,000	65,000	(91,800)
Long-Term Debt Borrowings	600,000	-	250,000
Long-Term Debt Repayments	(158,442)	(316,625)	(250,755)
Dividends Paid	(84,020)	(60,443)	(42,986)
Excess Tax Benefits from Stock-Based Compensation	27,339	28,188	-
Redemption of Preferred Stock	(51,197)	(50,199)	-
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	55,320	36,033	64,668
Debt Issuance Costs	(5,206)	(615)	(1,588)
Other, Net	(71)	(221)	151
Net Cash Provided by (Used in) Financing Activities	393,723	(298,882)	(72,310)
Effect of Exchange Rate Changes on Cash	4,662	5,146	3,823
(Decrease) Increase in Cash	(164,024)	(425,556)	622,831

and Cash Equivalents			
Cash and Cash Equivalents at Beginning of Year	218,255	643,811	20,980
Cash and Cash Equivalents at End of Year	$ 54,231	$ 218,255	$ 643,811

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.

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 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 (see Note 15). 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 depreciation, depletion and 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.

Other Property, Plant and Equipment

. Other Property, Plant and Equipment consist of natural gas gathering and processing facilities, natural gas compressors, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

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, 2007, 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

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gains or losses are recorded in Gains 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 Stockholders' 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.

During February 2007, the Financial Accounting Standards (FASB) issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FASB Statement No. 115." The new standard permits an entity to make an irrevocable election at specific election dates to measure most financial assets and financial liabilities at fair value. The fair value option may be elected on an instrument-by-instrument basis, with a few exceptions, as long as it is applied to the instrument in its entirety. Changes in fair value would be recorded in income. SFAS No. 159 established presentation and disclosure requirements intended to help financial statement users understand the effect of the entity's election on earnings. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007. Early adoption is permitted. Currently, EOG has elected not to adopt the fair value option provision allowed under SFAS No. 159.

In September 2006, 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

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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. As of December 31, 2006, EOG adopted the recognition and disclosure requirements of SFAS No. 158. The impact of the adoption was immaterial. 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, and will not have an 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. In February 2008, the FASB issued a Staff Position on SFAS No. 157, FASB Staff Position No. FAS 157-2, "Effective Date of FASB Statement No. 157," (FSP 157-2). FSP 157-2 delays the effective date of SFAS No. 157 for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008, except as provided by FSP 157-2. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those years. FSP 157-2 requires an entity that does not adopt SFAS No. 157 in its entirety to disclose, at each reporting date until fully adopted, that it has only partially adopted SFAS No. 157 and the categories of assets and liabilities recorded or disclosed at fair value to which SFAS No. 157 has not been applied. The adoption of SFAS No. 157 is not expected to have a material impact on EOG's financial statements, but will result in additional disclosures related to the use of fair values in the 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 has been reported as an increase to the opening balance of retained earnings for 2007 in the amount of $10.8 million, representing a reduction in the liability for unrecognized tax benefits. After the adoption of FIN No. 48, the balance of unrecognized tax benefits was zero. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. EOG had no such accrued interest and penalties as of the date of adoption of FIN No. 48.

2. Long-Term Debt

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

	2007	2006
6.50% Notes due 2007	$ -	$ 98,442
5.875% Notes due 2017	600,000	-
6.65% Notes due 2028	140,000	140,000
Subsidiary Senior Unsecured Term Loan Facility due 2008	-	60,000
Subsidiary Revolving Credit Facility due 2009	75,000	65,000
7.00% Subsidiary Debt due 2011	220,000	220,000
4.75% Subsidiary Debt due 2014	150,000	150,000
Total	$ 1,185,000	$ 733,442

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At December 31, 2007, the aggregate annual maturities of long-term debt were zero in 2008, $75 million in 2009, zero in 2010, $220 million in 2011 and zero in 2012. At December 31, 2006, the 6.50% Notes due 2007 were classified as long-term debt based on EOG's intent and ability to ultimately replace such amount with other long-term debt.

During 2007 and 2006, EOG utilized commercial paper and during August through December 2007, EOG utilized short-term funding from uncommitted credit facilities, both of which bear market interest rates. EOG had no commercial paper or borrowings from uncommitted facilities outstanding at December 31, 2007. The weighted average interest rate for commercial paper borrowings for 2007 was 5.53%. The weighted average interest rate for uncommitted facilities for the periods outstanding was 5.26%.

On December 3, 2007, EOG repaid the remaining $98 million principal amount of its 6.50% Notes due December 1, 2007 at par plus accrued and unpaid interest through the maturity date.

During the first nine months of 2007, EOGI International Company, a wholly owned foreign subsidiary of EOG, repaid the remaining $60 million year-end 2006 outstanding balance of its $600 million, 3-year unsecured Senior Term Loan Agreement (Loan Agreement). As previously reported, EOG terminated its remaining borrowing capacity under the Loan Agreement during July 2006.

On September 10, 2007, EOG completed its public offering of $600 million aggregate principal amount of 5.875% Senior Notes due 2017 (2017 Notes). Interest on the 2017 Notes is payable semi-annually on March 15 and September 15 of each year, beginning March 15, 2008. Net proceeds from the offering were approximately $595 million and were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

On May 18, 2007, EOG amended its 5-year, $600 million unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders and JP Morgan Chase Bank, N.A., as Administrative Agent, to increase the facility from $600 million to $1.0 billion and to provide EOG the option to request letters of credit to be issued in an aggregate amount of up to $1.0 billion, replacing the previous limitation of up to $200 million. Concurrent with the effectiveness of the amendment, the maturity date of the Agreement was extended from June 28, 2011 to June 28, 2012. On September 14, 2007, EOG further amended the Agreement to provide EOG the ability to borrow up to $150 million within the facility at interest rates based on overnight rates for Federal funds. At December 31, 2007, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate of the Agreement's administrative agent. At December 31, 2007, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 4.68% and 7.25%, respectively.

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 the Eurodollar rate or the base rate of the Credit Agreement's administrative agent. EOG had $75 million outstanding under the Credit Agreement at December 31, 2007. The applicable interest rate at December 31, 2007 was 5.63%. The weighted average Eurodollar rate for the amounts outstanding during the year ended December 31, 2007 was 5.68%.

The 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.

The 5.875% and 6.65% Notes due 2017 and 2028, respectively, were issued through public offerings and have effective interest rates of 5.971% and 6.65%, respectively. The Subsidiary Debt due 2011 bears interest at a fixed rate of 7.00% and is guaranteed by EOG.

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/or common stock. The New Registration Statement was filed to replace EOG's then-existing shelf registration statement, which had been declared effective by the SEC in October 2000 and under which EOG had sold no securities. As of December 31, 2007, and as a result of the issuance of the 2017 Notes, EOG may offer and sell up to $88,237,500 of its debt securities, preferred stock and/or common stock under the New Registration Statement.

Fair Value of Long-Term Debt.

At December 31, 2007 and 2006, EOG had $1,185 million and $733 million, respectively, of long-term debt, which had fair values of approximately $1,227 million and $754 million, respectively. The fair value of long-term debt is the value EOG would have to pay to retire the debt, including any premium or discount to the debtholder for the differential between the stated interest rate and the year-end market rate. The fair value of long-term debt is based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at year-end.

3. Stockholders' 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, EOG's Board of Directors (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, 2007, 6,386,200 shares remained available for repurchases under this authorization. On February 2, 2005, EOG announced that its 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. The Board increased the quarterly cash dividend on the common stock to $0.06 per share on February 1, 2006, to $0.09 per share on January 31, 2007 and to $0.12 per share on February 7, 2008.

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, 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 Under Employee Stock Purchase Plan	-	106	106
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
Treasury Stock Purchased	-	(126)	(126)
Treasury Stock Issued Under Stock Option Plans	-	1,775	1,775
	-	102	102

Treasury Stock Issued Under			
Employee Stock Purchase Plan			
Restricted Stock and Units	-	1,039	1,039
Balance at December 31, 2007	249,460	(2,935)	246,525

Common Stock Rights Agreement

. On February 14, 2000, the Board declared a dividend of one preferred share purchase right (a Right, and the agreement governing the terms of such Rights, as amended, the Rights Agreement) for each outstanding share of EOG common stock to stockholders of record on that date. The Board adopted this Rights Agreement to protect stockholders from coercive or otherwise unfair takeover tactics. In accordance with the Rights Agreement, each share of common stock issued in connection with the two-for-one stock split, effected March 1, 2005, also had one Right associated with it. Each Right, expiring February 24, 2010, represents a right to buy from EOG one two-hundredth (1/200) of a share of EOG's 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 stockholder approximately the same dividend, voting, and liquidation rights as would one share of common stock. Prior to exercise, the Right does not give its holder any dividend, voting, or liquidation rights. If issued, each one two-hundredth (1/200) of a Series E share (i) will not be redeemable; (ii) will entitle holders to quarterly dividend payments of $0.005 per one two-hundredth (1/200) of a 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 $0.50 per one two-hundredth (1/200) of a 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 (as defined in the Rights Agreement) by obtaining beneficial ownership of 10% or more of EOG's common stock or, if earlier, 10 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 (or publicly announces the intent to make) a tender or exchange offer which, if consummated, would result in that person or group becoming the beneficial owner of 10% or more of EOG's common stock. In February 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, as amended, 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 SEC 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). In June 2005, the Rights Agreement was amended to revise 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 each Right held, purchase at a price of $90 (as adjusted pursuant to the Rights Agreement) shares of EOG's common stock with a market value of $180 (based on the market price of the common stock on the date that such person or group becomes an Acquiring Person). If EOG is acquired in a merger or similar transaction after a person or group has become an Acquiring Person, all holders of Rights, except the Acquiring Person, may, for each Right held, purchase at a price of $90 (as adjusted pursuant to the Rights Agreement) shares of the acquiring corporation's stock with a market value of $180 (based on the market price of the acquiring corporation's stock on the date of such merger or similar transaction).

EOG's Board may redeem all (but not less than all) of the Rights for $0.005 per Right at any time before any person or group becomes an Acquiring Person once the Board acts to redeem the Rights. Theholders of Rights shall only have the right to receive the redemption price. The redemption price has been adjusted (from $0.010 to $0.005) for the two-for-one stock split effected 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 any person beneficially owns 50% or more of EOG's outstanding common stock, the Board may exchange all or part of the outstanding and exercisable Rights for common stock or an equivalent security at an exchange ratio of one share of common stock or 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. In February 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. In February 2005, EOG's Board increased the authorized shares of the Series E to 3,000,000 in connection with the two-for-one stock split of EOG's common stock effected in March 2005. As of December 31, 2007, there were no shares of the Series E outstanding.

In July 2000, EOG's Board authorized 100,000 shares of 7.195% Fixed Rate Cumulative Perpetual Preferred Stock, Series B, with a $1,000 liquidation preference per share (Series B). Dividends are payable quarterly, in cash, on the shares of the Series B as declared by EOG's Board at a rate of $71.95 per share per year, on March 15, June 15, September 15 and December 15 of each year.

In October 2006, EOG commenced a cash tender offer to purchase any and all of the 100,000 then-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 in November 2006, and EOG redeemed 46,740 shares of the Series B for an aggregate purchase price, including redemption premium, fees and dividends, of approximately $51 million. EOG included the $4 million of premium and fees associated with the redemption of the Series B shares as a component of preferred stock dividends for fiscal year 2006.

In 2007, EOG repurchased a total of 48,260 shares of its outstanding Series B for an aggregate purchase price, including premium and fees, of $51 million, plus accrued dividends up to the date of repurchase. EOG has included as a component of preferred stock dividends the $3 million of premium and fees associated with the repurchase. At December 31, 2007, 5,000 shares of the Series B with a book value of $5 million remained outstanding.

In January 2008, EOG repurchased the remaining outstanding 5,000 shares of the Series B for approximately $5.4 million plus accrued dividends up to the date of repurchase. The premium of $0.4 million associated with the repurchase will be included as a component of preferred stock dividends for fiscal year 2008.

4. Other Income, Net

Other income, net for 2007 included interest income ($10 million), equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants ($16 million) and net foreign currency transaction gains ($4 million). Other income, net for 2006 included interest income ($27 million), equity income from investments in CNCL and N2000 ammonia plants ($18 million) and settlements received related to the Enron Corp. bankruptcy ($4 million).

5. Income Taxes

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

	2007	2006
Current Deferred Income Tax Assets (Liabilities)		
Commodity Hedging Contracts	$ (37,247)	$ -
Deferred Compensation Plans	11,775	-
Alternative Minimum Tax Credit Carryforward	50,000	-
Other	9,005	-
Total Net Current Deferred Income Tax Assets	$ 33,533	$ -
Current Deferred Income Tax (Assets) Liabilities		
Commodity Hedging Contracts	$ -	$ 50,786
Deferred Compensation Plans	-	(9,501)
Timing Differences Associated With Different Year-ends in Foreign Jurisdictions	108,207	121,677
Other	773	(18,347)
Total Net Current Deferred Income Tax Liabilities	$ 108,980	$ 144,615
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 2,267,948	$ 1,658,124
Non-Producing Leasehold Costs	(67,824)	(59,862)
Seismic Costs Capitalized for Tax	(46,546)	(53,777)
Equity Awards	(32,130)	(11,688)
Capitalized Interest	35,424	26,957
Alternative Minimum Tax Credit Carryforward	(35,537)	-
Other	(50,028)	(46,626)
Total Net Noncurrent Deferred Income Tax Liabilities	$ 2,071,307	$ 1,513,128
Total Net Deferred Income Tax Liabilities	$ 2,146,754	$ 1,657,743

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

	2007	2006	2005
United States	$ 1,191,093	$ 1,343,669	$ 1,336,658
Foreign	439,775	568,972	628,479
Total	$ 1,630,868	$ 1,912,641	$ 1,965,137

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

	2007	2006	2005
Current:			
Federal	$ (7,284)	$ 78,910	$ 333,752
State	(3,999)	1,050	25,527
Foreign	125,406	146,954	75,991
Total	114,123	226,914	435,270
Deferred:			
Federal	416,925	377,543	132,118
State	26,506	11,475	14,774
Foreign	(16,604)	(3,176)	123,399
Total	426,827	385,842	270,291
Income Tax Provision	$ 540,950	$ 612,756	$ 705,561

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

	2007	2006	2005
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	0.90	0.15	1.32
Income Tax Provision Related to Foreign Operations	(0.67)	(0.10)	(0.92)
Change in Canadian Federal and Provincial Statutory Tax Rates and			

Other Canadian Adjustments	(2.10)	(3.18)	-
Change in United Kingdom Tax Rates	-	0.38	-
Change in Texas Tax Rates	-	0.27	-
Dividend Repatriation	-	-	1.20
Domestic Production Activities Deduction	0.11	(0.06)	(0.42)
Other	(0.07)	(0.42)	(0.28)
Effective Income Tax Rate	33.17%	32.04%	35.90%

As indicated in Note 1, EOG adopted FIN No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109," as of January 1, 2007. After the adoption of FIN No. 48, the balance of unrecognized tax benefits was zero. There have been no increases or decreases in unrecognized tax benefits during the year. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. EOG has no such interest or penalties as of the date of adoption of FIN No. 48, and none have been recorded during 2007. EOG and its subsidiaries file income tax returns in the United States and various state, local and foreign jurisdictions. EOG is generally no longer subject to income tax examinations by tax authorities in the United States (federal), Canada, the United Kingdom and Trinidad for taxable years before 2004, 2002, 2005 and 1999, respectively.

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 $2.4 billion at December 31, 2007 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.

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In 2007, EOG had a regular tax net operating loss of $278 million, which is expected to be carried back and applied against 2005 regular taxable income. As a result of the loss carryback, EOG will receive a refund of 2005 income taxes. Additionally, in 2007 EOG paid alternative minimum tax (AMT) of $65 million. The AMT paid in 2007, along with AMT paid in 2006 of $21 million, will be carried forward as a credit available to offset regular income taxes in future periods.

6. Employee Benefit Plans

Pension Plans and Postretirement Benefits

At December 31, 2007, 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, "Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R)," as of the year ended December 31, 2006. The impact of the adoption was immaterial. 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, and will not have an 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. During 2007, approximately $0.2 million of such costs was amortized from accumulated other comprehensive income through net periodic benefit costs.

Pension Plans.

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. EOG's contributions to these pension plans are based on various percentages of compensation, and in some instances, are based upon the amount of the employees' contributions. EOG's total costs recognized for these plans were $16 million, $14 million and $12 million for 2007, 2006 and 2005, 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 non-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 plans were $2.7 million, $2.1 million and $2.0 million for 2007, 2006 and 2005, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and prepaid/(accrued) benefit cost totaled $7.3 million, $7.3 million and $0.03 million, respectively, at December 31, 2007 and $6.7 million, $6.0 million and ($0.7) million, respectively, at December 31, 2006. Weighted average discount rate, expected return on plan assets, rate of compensation increase and rate of pension increase assumptions used to determine net periodic benefit cost for the pension plans were 3.30%, 7.13%, 4.52% and 2.32%, respectively, at December 31, 2007; 5.98%, 7.10%, 4.20% and 2.40%, respectively, at December 31, 2006; and 6.50%, 6.57%, 5.50% and 0.00%, respectively, at December 31, 2005. Weighted average discount rate, rate of compensation increase and rate of pension increase assumptions used to determine benefit obligations for the pension plans were 6.43%, 4.52% and 2.32%, respectively, for the year ended December 31,2007 and 5.75%, 4.20% and 2.40%, respectively, for the year ended December 31, 2006. The weighted average asset allocation of the pension plans at December 31, 2007 consisted of equities (56%), debt and fixed income securities (39%) and other assets (6%). The asset allocation at December 31, 2006 consisted of equities (55%), debt and fixed income securities (40%) 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 restrict 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 maintains a pension plan 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 and $0.1 million for 2007 and 2006, respectively.

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 $4.0 million and $3.9 million at December 31, 2007 and $3.7 million each, respectively, at December 31, 2006. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2007 and 2006 were 6.29% and 5.95%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2007, 2006 and 2005 were 5.96%, 5.68% and 5.98%, respectively. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.7 million, $0.7 million and $0.4 million for the years ended December 31, 2007, 2006 and 2005.

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
2008	$ 251	$ 142
2009	277	181
2010	273	204
2011	322	241
2012	290	268
2013 - 2017	2,362	2,160

Postretirement health care trend rates had minimal effect on the amounts reported for the postretirement health care plans for both 2007 and 2006. Most future increases or decreases in healthcare costs would be borne by the employee.

Stock-Based Compensation

At December 31, 2007, EOG maintained various stock-based compensation plans as discussed below. EOG adopted 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. 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, "Accounting for Stock Issued to Employees," 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 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 and Comprehensive Income based upon job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years ended December 31, was as follows (in millions):

	2007	**2006**	**2005**
Lease and Well	$ 14	$ 10	$ -
Exploration Costs	13	11	-
General and Administrative	40	29	12
Total(1)	$ 67	$ 50	$ 12

(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.

Had compensation costs been recorded in accordance with SFAS No. 123, EOG's pro forma 2005 net income available to common stockholders, basic net income per share available to common stockholders and diluted net income per share available to common stockholders would have been $1,238.4 million, $5.19 per share and $5.08 per share, respectively.

EOG has various stock plans (Plans) under which employees and non-employee members of the Board 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, 2007, 1,139,925 shares remain available for grant under the plans.

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. In addition, participants have been or may be granted SARs representing 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 are granted at a price not less than the market price of the stock on the date of grant. 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. The fair value of all grants made prior to August 2004 and all ESPP grants 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 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 $36.7 million and $34.8 million for the years ended December 31, 2007 and 2006, respectively.

Weighted average fair values and valuation assumptions used to value stock options, SARs and ESPP grants for the years ended December 31, were as follows:

Stock Options/SARs			ESPP		
2007	2006	2005	2007	2006	2005

Weighted Average Fair Value of Grants	$24.23	$22.56	$19.82	$16.11	$20.32	$ 9.81
Expected Volatility	30.68%	34.22%	31.92%	29.76%	41.09%	30.32%
Risk-Free Interest Rate	4.48%	4.96%	4.15%	5.01%	4.89%	2.98%
Dividend Yield	0.30%	0.30%	0.36%	0.30%	0.30%	0.38%
Expected Life	5.2 yrs	5.1 yrs	5.0 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):

	2007		2006		2005	
	Number of Stock Options/ SARs	Weighted Average Grant Price	Number of Stock Options/ SARs	Weighted Average Grant Price	**Number of** Stock Options	Weighted Average Grant Price
Outstanding at January 1	10,150	$35.29	9,698	$28.26	11,922	$19.78
Granted	1,210	73.46	2,038	62.25	1,823	61.57
Exercised(1)	(1,820)	29.12	(1,368)	23.80	(3,804)	17.61
Forfeited	(167)	56.39	(218)	42.03	(243)	28.86
Outstanding at December 31	9,373	41.04	10,150	35.29	9,698	28.26
Options/SARs Exercisable at December 31	5,617	27.21	5,325	20.91	4,575	16.61
Available for Future Grant	1,140		3,233		5,606	

(1) The total intrinsic value of stock options/SARs exercised during the years 2007, 2006 and 2005 was $86.4 million, $65.0 million and $154.5
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, 2007, there are 9,126,521 stock options/SARs vested or expected to vest with a weighted average grant price of $40.44, an intrinsic value of $445 million and a weighted average remaining contractual life of 4.9 years.

At December 31, 2007, unrecognized compensation expense related to non-vested stock options, SARs and ESPP grants totaled $72.3 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.2 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2007 (stock options and SARs in thousands):

	Stock Options/SARs Outstanding				Stock Options/SARs Exercisable			
Range of Grant Prices	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value(1)	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value(1)
$ 7.00 to $16.99	1,402	3	$14.86		1,402	3	$14.86	
17.00 to 19.99	2,064	4	18.21		2,063	4	18.21	
20.00 to 48.99	1,541	6	26.22		1,025	5	23.16	
49.00 to 69.99	3,084	5	61.92		1,059	5	62.02	
70.00 to 86.99	1,282	7	74.01		68	7	73.85	
	9,373	5	41.04	$451,848	5,617	4	27.21	$348,480

(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 generally vest five years after the date of grant, except for certain bonus 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 $30 million, $15 million and $12 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The following table sets forth the restricted stock and units transactions for the years ended December 31 (shares, units and dollars in thousands, except per share data):

	2007		2006		2005	
	Number of Shares and	Weighted Average Grant Date	Number of Shares and	Weighted Average Grant Date	Number of Shares and	Weighted Average Grant Date

	Units	Fair Value	Units	Fair Value	Units	Fair Value
Outstanding at January 1	2,301	$36.13	2,544	$26.04	2,566	$19.90
Granted	1,141	71.28	542	64.29	385	52.19
Released[1]	(346)	21.20	(702)	20.74	(353)	9.57
Forfeited	(96)	54.58	(83)	41.50	(54)	27.91
Outstanding at December 31[2]	3,000	50.61	2,301	36.13	2,544	26.04

(1) The total intrinsic value of restricted stock and units released during the years ended December 31, 2007, 2006 and 2005 was
$23.8 million, $50.3 million and $14.6 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, 2007 and 2006 was approximately $267.7 million
and $143.7 million, respectively.

At December 31, 2007, unrecognized compensation expense related to restricted stock and units totaled $102.8 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.7 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, 2007, approximately 213,300 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):

	2007	2006	2005
Approximate Number of Participants	860	730	580
Shares Purchased	102	92	106
Aggregate Purchase Price	$5,840	$5,110	$3,889

During 2007, 2006 and 2005, 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 $29 million, $31 million and $51 million for 2007, 2006 and 2005, 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, 2007, EOG had standby letters of credit and guarantees outstanding totaling approximately $583 million of which $445 million represents guarantees of subsidiary indebtedness included under Note 2 "Long-Term Debt" and $138 million primarily represents guarantees of payment obligations on behalf of subsidiaries. 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 and $125 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 27, 2008, there were no demands for payment under these guarantees.

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Minimum Commitments.

At December 31, 2007, 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, 2007, are as follows (in thousands):

	Total Minimum Commitments
2008	$ 412,639
2009 - 2010	606,458
2011 - 2012	412,189
2013 and beyond	1,122,769
	$2,554,055

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 $60 million, $46 million and $34 million for 2007, 2006 and 2005, respectively.

Contingencies.

There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted with certainty, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. In accordance with SFAS No. 5, "Accounting for Contingencies," EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

8. Net Income Per Share Available to Common Stockholders

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

	2007	2006	2005

Numerator for Basic and Diluted Earnings per Share -			
Net Income	$1,089,918	$1,299,885	$1,259,576
Less: Preferred Stock Dividends	6,663	10,995	7,432
Net Income Available to Common Stockholders	$1,083,255	$1,288,890	$1,252,144
Denominator for Basic Earnings per Share -			
Weighted Average Shares	243,469	241,782	238,797
Potential Dilutive Common Shares -			
Stock Options/SARs	2,915	3,261	3,942
Restricted Stock and Units	1,253	1,057	1,236
Denominator for Diluted Earnings per Share -			
Adjusted Weighted Average Shares	247,637	246,100	243,975
Net Income Per Share Available to Common Stockholders			
Basic	$ 4.45	$ 5.33	$ 5.24
Diluted	$ 4.37	$ 5.24	$ 5.13

The diluted earnings per share calculation excludes stock options/SARs that were anti-dilutive. The excluded stock options/SARs totaled 2.4 million, 0.1 million and 1.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

9. Supplemental Cash Flow Information

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

	2007	2006	2005
Interest	$ 38,616	$ 41,174	$ 60,467
Income taxes	$ 144,234	$ 301,214	$ 335,628

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
2007						
Natural Gas	$2,239,060	$ 510,473	$248,553	$ 52,887	$ -	$ 3,050,973
Crude Oil, Condensate and Natural Gas Liquids	806,037	74,841	104,324	2,321	-	987,523
Gains on Mark-to-Market Commodity Derivative Contracts	93,108	-	-	-	-	93,108
Other, Net	59,369	(50)	(133)	1	-	59,187
Net Operating Revenues[(1)]	3,197,574	585,264	352,744	55,209	-	4,190,791
Depreciation, Depletion and Amortization	848,051	170,666	24,883	21,945	-	1,065,545
Operating Income (Expense)	1,199,816	197,207	247,638	3,996	(261)	1,648,396
Interest Income	850	2,474	5,226	1,143	-	9,693

Other Income (Expense)	7,384	(4,348)	16,609	(94)	6	19,557
Net Interest Expense	20,262	20,391	6,148	(23)	-	46,778
Income (Loss) Before Income Taxes	1,187,788	174,942	263,325	5,068	(255)	1,630,868
Income Tax Provision (Benefit)	427,531	(6,728)	116,684	3,463	-	540,950
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	2,810,265	355,474	109,273	11,592	-	3,286,604
Total Property, Plant and Equipment, Net	7,364,648	2,543,781	472,096	48,729	-	10,429,254
Total Assets	8,687,320	2,649,925	692,353	58,255	1,054	12,088,907
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	8,403	(3)	11	5,046	-	13,457
Net Operating Revenues(2)	2,881,700	593,674	345,688	91,480	-	3,912,542
Depreciation, Depletion and Amortization	623,311	143,368	26,623	23,787	-	817,089
Operating Income (Expense)	1,324,215	277,009	250,470	52,384	(525)	1,903,553
Interest Income	17,159	4,861	4,697	-	-	26,717
Other Income (Expense)	12,872	(6,412)	18,925	139	5	25,529
Net Interest Expense	11,597	21,531	9,988	42	-	43,158
Income (Expense) Before Income Taxes	1,342,649	253,927	264,104	52,481	(520)	1,912,641

Income Tax Provision	463,948	13,286	107,648	27,874	-	612,756
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	2,107,006	416,834	117,668	29,187	-	2,670,695
Total Property, Plant and Equipment, Net	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

	United States	Canada	Trinidad	United Kingdom	Other	Total
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	15,366	(65)	-	263	-	15,564
Net Operating Revenues(3)	2,597,032	651,284	280,622	104,091	-	3,633,029
Depreciation, Depletion and Amortization	488,621	124,793	24,781	16,063	-	654,258
Operating Income	1,369,282	377,516	204,133	53,700	-	2,004,631
Interest Income	1,218	2,139	4,510	-	-	7,867
Other Income (Expense)	6,336	(4,965)	17,631	(3,857)	-	15,145
Net Interest Expense	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	1,259,739	307,862	42,384	10,500	-	1,620,485

Properties, Excluding Dry Hole Costs						
Total Property, Plant and Equipment, Net	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

(1) EOG had no significant purchaser in 2007 whose sales totaled 10 percent or more of consolidated Net Operating Revenues.
(2) 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.
(3) 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.

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, "Accounting for Derivative Instruments and Hedging Activities," 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 2007, 2006 and 2005, 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 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included realized gains of $128 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.

Presented below is a comprehensive summary of EOG's 2008 natural gas and crude oil financial price swap contracts at December 31, 2007 with notional volumes in million British thermal units per day (MMBtud) and in barrels per day (Bbld), as applicable, and prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), as applicable. For information on additional financial price swap contracts entered into subsequent to December 31, 2007, see Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. 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, 2007 was $98 million.

Financial Price Swap Contracts

	Natural Gas		Crude Oil	
		Weighted		Weighted

	Volume (MMBtud)	Average Price ($/MMBtu)	Volume (Bbld)	Average Price ($/Bbl)
2008				
January (closed)	385,000	$8.92	-	$ -
February (1)	385,000	8.94	4,000	88.79
March	385,000	8.74	4,000	88.79
April	385,000	8.11	4,000	88.79
May	385,000	8.09	4,000	88.79
June	385,000	8.17	4,000	88.79
July	385,000	8.25	4,000	88.79
August	385,000	8.32	4,000	88.79
September	385,000	8.36	4,000	88.79
October	385,000	8.44	4,000	88.79
November	385,000	8.85	4,000	88.79
December	385,000	9.27	2,000	87.60

(1) The natural gas contracts for February 2008 are closed. The crude oil contracts for February 2008 will close on February 29, 2008.

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

	2007		2006	
	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
Long-Term Debt(2)	$ 1,185	$ 1,227	$ 733	$ 754
NYMEX-Related Commodity Market Positions	98	98	131	131
Foreign Currency Swap Liability	58	58	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, 2007, no individual purchaser's net accounts receivable balance related to United States and Canada hydrocarbon sales accounted for 10% or more of the total balance. At December 31, 2006, an integrated oil and gas company accounts receivable balance related to United States and Canada hydrocarbon sales accounted for 12% of the total balance. In 2007 and 2006, natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago.

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At December 31, 2007, EOG had an allowance for doubtful accounts of $16 million, of which $14 million is associated with the Enron Corp. bankruptcies recorded in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2007 and 2006 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, 2007, 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 2007, 2006 and 2005, 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 $60 million, $48 million and $31 million in the United States operating segment during 2007, 2006 and 2005, respectively, and $22 million and $7 million in the Canada operating segment during 2007 and 2006, 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 $66 million, $53 million and $47 million for 2007, 2006 and 2005, respectively.

13. Accounting for Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of short-term and long-term legal obligations associated with the retirement of oil and gas properties at December 31 (in thousands):

	2007	2006
Carrying Amount at Beginning of Period	$182,406	$161,488

Liabilities Incurred	26,210	19,921
Liabilities Settled	(18,072)	(8,499)
Accretion	10,187	8,537
Revisions	2,973	(53)
Foreign Currency Translations	7,420	1,012
Carrying Amount at End of Period	$211,124	$182,406
Current Portion	$ 4,781	$ 9,507
Noncurrent Portion	$206,343	$172,899

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 quarter of 2005, EOG completed a share sale agreement whereby portions of the EOG subsidiaries' shareholdings in CNCL and N2000 were sold to a third party energy company which resulted in a pretax gain of $2 million. At December 31, 2007, EOG's equity interests in CNCL and N2000 were 12% and 10%, respectively.

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At December 31, 2007, the investment in CNCL was $19 million. CNCL commenced ammonia production in June 2002. At December 31, 2007, CNCL had a long-term debt balance of $111 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. Since inception, there have been no borrowings under this agreement. 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 2007, EOG recognized equity income of $8 million and received cash dividends of $8

million from CNCL.

At December 31, 2007 the investment in N2000 was $17 million. N2000 commenced ammonia production in August 2004. At December 31, 2007, N2000 had a long-term debt balance of $136 million, which is non-recourse to N2000's shareholders. At December 31, 2007, 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. Since inception, there have been no borrowings under this agreement. 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 2007, EOG recognized equity income of $8 million and received cash dividends of $8 million

from N2000.

15. Suspended Well Costs

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

	Year Ended December 31,		
	2007	2006	2005
Balance at January 1	$ 77,365	$ 27,868	$20,520
Additions Pending the Determination of Proved Reserves	132,993	64,449	18,533
Reclassifications to Proved Properties	(23,716)	(10,474)	(9,245)
Charged to Dry Hole Costs	(18,232)	(3,901)	(2,267)
Foreign Currency Translations	6,105	(577)	327
Other	(25,634)(1)	-	-
Balance at December 31	$148,881	$ 77,365	$27,868

(1) During 2007, EOG decided to no longer participate in the further evaluation of the Northwest Territories discovery and sold all of its interest to the outside operator for $5 million. Prior to the sale, EOG recorded an impairment charge of approximately $21 million.

The following table provides an aging of suspended well costs at December 31 (in thousands, except well count):

	Year Ended December 31,		
	2007	2006	2005
Capitalized exploratory well costs that have been capitalized	$ 97,621	$50,589	$14,878

for a period less than one year			
Capitalized exploratory well costs that have been capitalized for a period greater than one year	51,257(1)	26,776(2)	12,990(3)
Total	$148,88[illegible]	$77,365	$27,868
Number of exploratory wells that have been capitalized for a period greater than one year	2	2	2

(1) Costs related to a shale project in British Columbia (B.C.), Canada ($38 million) and an outside operated, offshore Central North Sea project in the United Kingdom ($13 million). In the B.C. project, EOG drilled and completed an initial well in late 2006 that tested natural gas from two zones. In the first quarter of 2008, EOG will complete two additional wells that were drilled in late 2007 to further test one of the zones. In the Central North Sea project, EOG participated in the drilling and successful testing of an exploratory well and an appraisal well. EOG is currently participating in the preparation of development options for this project.

(2) 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).

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

16. Subsequent Events

In December 2007, EOG entered into an agreement to sell the majority of its producing shallow gas assets and surrounding acreage in the Appalachian Basin to a subsidiary of EXCO Resources, Inc., an independent oil and gas company, for approximately $395 million, subject to customary adjustments under the agreement. The Appalachian area being divested includes approximately 2,400 operated wells that accounted for approximately 1% of EOG's total 2007 production and approximately 2% of its total year-end 2007 proved reserves. The transaction closed on February

20, 2008. EOG retained certain of its undeveloped acreage in this area, including rights in the Marcellus Shale, and will continue its shale exploration program. On December 31, 2007, the book value of the assets and liabilities included in the sale were $254 million and $9 million, respectively.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

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

Oil and Gas Producing Activities

The following disclosures are made in accordance with 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.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimates of proved and proved developed reserves at December 31, 2007, 2006 and 2005 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, 2007, 2006 and 2005 covered producing areas containing 79%, 82% and 82%, 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, 2007 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, 2007, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2007, 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, 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
Revisions of previous estimates	(63.2)	(64.3)	(16.9)	2.5	(141.9)

Purchases in place	1.2	1.2	29.6	-	32.0
Extensions, discoveries and other additions	1,177.5	54.9	-	-	1,232.4
Sales in place	(5.7)	-	-	-	(5.7)
Production	(360.6)	(81.6)	(91.8)	(8.6)	(542.6)
Net proved reserves at December 31, 2007	4,220.1	1,219.8	1,216.3	12.9	6,669.1

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, 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
Revisions of previous estimates	27,933	1,169	(1,179)	20	27,943
Purchases in place	37	-	69	-	106
Extensions, discoveries and other additions	49,418	886	-	-	50,304
Sales in place	(940)	-	-	-	(940)
Production	(13,043)	(1,269)	(1,494)	(35)	(15,841)
Net proved reserves at December 31, 2007	160,021	10,366	8,900	47	179,334
Bcf Equivalent (Bcfe)					
(1)					
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
Revisions of previous estimates	104.4	(57.3)	(23.9)	2.6	25.8
Purchases in place	1.5	1.2	30.0	-	32.7
Extensions, discoveries and other additions	1,474.0	60.2	-	-	1,534.2
Sales in place	(11.4)	-	-	-	(11.4)
Production	(438.9)	(89.2)	(100.8)	(8.8)	(637.7)
Net proved reserves at December 31, 2007	5,180.2	1,282.0	1,269.7	13.2	7,745.1

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, 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
December 31, 2007	3,141.8	1,079.1	916.7	12.9	5,150.5
Liquids (MBbl) [(2)]					
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
December 31, 2007	119,949	10,193	7,222	47	137,411
Bcf Equivalents (Bcfe) [(1)]					
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
December 31, 2007	3,861.5	1,140.3	960.0	13.2	5,975.0

(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:

	2007	2006
Proved properties	$16,299,661	$13,069,046
Unproved properties	682,175	506,482
Total	16,981,836	13,575,528
Accumulated depreciation, depletion and amortization	(6,957,550)	(5,804,470)
Net capitalized costs (1)	$10,024,286	$ 7,771,058

(1) Amounts for 2007 exclude long-term assets held for sale of $254,376.

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 States	Canada	Trinidad	United Kingdom	Other	Total
2007						
Acquisition Costs of Properties						
Unproved	$ 233,337	$ 45,842	$ (38)	$ (1,141)	$ -	$ 278,000
Proved	3,887	696	15,414	-	-	19,997
Subtotal	237,224	46,538	15,376	(1,141)	-	297,997
Exploration Costs	435,944	75,531	45,161	27,805	5,299	589,740
Development Costs (1)	2,358,258	263,547	91,242	(1,417)	-	2,711,630
Total	$ 3,031,426	$ 385,616	$ 151,779	$ 25,247	$ 5,299	$ 3,599,367
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 (2)	1,744,301	339,602	79,712	17,945	-	2,181,560
Total	$ 2,304,081	$ 442,395	$ 136,649	$ 37,018	$ 7,037	$ 2,927,180
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 (3)	952,345	287,303	25,769	15,259	-	1,280,676
Total	$ 1,397,411	$ 354,475	$ 50,198	$ 33,299	$ 2,844	$ 1,838,227

(1) Includes Asset Retirement Costs of $22 million, $9 million, zero and zero for the United States, Canada, Trinidad and the United Kingdom,
respectively. Excludes other property, plant and equipment.
(2) 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. Excludes other property, plant and equipment.

(3) Includes Asset Retirement Costs of $8 million, $11 million, zero and $1 million for the United States, Canada, Trinidad and the United Kingdom, respectively. Excludes other property, plant and equipment.

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
2007						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$3,045,097	$585,314	$352,877	$ 55,208	$ -	$4,038,496
Other	15,655	(105)	8	1	-	15,559
Total	3,060,752	585,209	352,885	55,209	-	4,054,055
Exploration Costs	120,982	15,500	7,577	6,132	254	150,445
Dry Hole Costs	83,160	5,349	19,350	7,523	-	115,382
Transportation Costs	154,798	8,880	-	6,726	-	170,404
Production Costs	481,990	136,952	45,640	3,375	-	667,957
Impairments	108,037	37,076	-	2,404	-	147,517
Depreciation, Depletion and Amortization	848,051	170,666	24,883	21,945	-	1,065,545
Income (Loss) Before Income Taxes	1,263,734	210,786	255,435	7,104	(254)	1,736,805
	454,923	68,084	112,709	3,552	(89)	639,179

Income Tax Provision (Benefit)						
Results of Operations	$ 808,811	$ 142,702	$ 142,726	$ 3,552	$ (165)	$ 1,097,626
2006						
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 2,539,037	$ 593,677	$ 345,677	$ 86,434	$ -	$ 3,564,825
Other	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	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

(1) Excludes gains or losses on mark-to-market financial commodity derivative contracts, gains or losses on sales of reserves and related assets, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2007.

(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
2007					
Future cash inflows(1)					