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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

or

☐ **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	**47-0684736**
(State or other jurisdiction of incorporation or organization)	(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 ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

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. ☐

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.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

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, 2008: $32,634,838,355.

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, 249,690,094 shares outstanding as of February 17, 2009.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2009 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2008 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, Trinidad, the United Kingdom North Sea, China 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 United States Securities and Exchange Commission (SEC). EOG's website address is http://www.eogresources.com.

At December 31, 2008, EOG's total estimated net proved reserves were 8,689 billion cubic feet equivalent (Bcfe), of which 7,339 billion cubic feet (Bcf) were natural gas reserves and 225 million barrels (MMBbl), or 1,350 Bcfe, were crude oil and condensate and natural gas liquids reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 71% of EOG's reserves (on a natural gas equivalent basis) were located in the United States, 15% in Canada and 14% in Trinidad. As of December 31, 2008, EOG employed approximately 2,100 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 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, formation logging techniques and reservoir stimulation/completion 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, 2008, 82% of EOG's net proved United States and Canada reserves (on a natural gas equivalent basis) were natural gas and 18% were crude oil and 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 utilization of the applicable technologies described above. 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 2008 and certain 2009 plans for EOG's United States and Canada operations.

United States. EOG continues to grow production and future reserve potential in the Barnett Shale play of the Fort Worth Basin. In 2008, EOG began selling production from 410 net wells drilled during the year and grew production to a net average daily rate of 413 million cubic feet per day (MMcfd) of natural gas and 6.6 thousand barrels per day (MBbld) of crude oil and condensate and natural gas liquids. At year-end 2008, EOG's net production had increased to approximately 509 million cubic feet equivalent per day (MMcfed), and net acreage held was approximately 990,000 acres. During 2008, EOG continued to experience successful drilling in Johnson, Hill, and the western extension counties of the Barnett Shale gas play. Additionally, EOG saw successful drilling in the Barnett Combo play located in the northern portion of the Fort Worth Basin. The Barnett Combo play was previously known as the Barnett Oil play but, as a result of the wells in this play producing roughly one-third crude oil, one-third natural gas liquids and one-third natural gas, the name Combo seemed more appropriate. For 2009, EOG plans to begin selling production from approximately 260 net wells. With a focus on maximizing the recovery of hydrocarbons in place and cost reduction, EOG expects the Barnett Shale play to continue to add production and reserve growth to EOG for many years to come.

EOG significantly expanded its activities in 2008 throughout the Rocky Mountain area where it holds approximately 1.6 million net acres. During 2008, 353 net wells were drilled. In the core areas, 210 net wells were drilled in the Uinta Basin, Utah, 64 net wells were drilled in North Dakota and Montana in the Williston Basin, 45 net wells were drilled in the Moxa Arch area of Wyoming and 21 net wells were drilled in the LaBarge Platform, Wyoming. Production from the Rocky Mountain area increased 57% with this expanded drilling activity. The net average production for 2008 was 232 MMcfd of natural gas and 26.6 MBbld of crude oil and condensate and natural gas liquids. EOG ended 2008 producing approximately 24 MBbld, net of crude oil from the Bakken play in North Dakota and intends to drill over 45 net wells in the play in 2009. The majority of the production growth in the Rocky Mountain area was derived from very active drilling programs in the North Dakota Bakken and the Uinta Basin Mesaverde development plays. EOG expects to remain active in these two areas in 2009 and plans to continue its exploration program throughout the Rocky Mountain area.

In the Mid-Continent area, EOG drilled 106 net wells during 2008 in its core areas in Southwest Kansas, the Oklahoma Panhandle and the Texas Panhandle. The net average production for 2008 was 84 MMcfd of natural gas and 4.7 MBbld of crude oil and condensate which represents an 11% total production increase over 2007. 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 seven years remaining on an approximately 900,000 gross acre, 10-year farm-in agreement from Anadarko Petroleum Company. In addition to its existing Cleveland Horizontal play in the Texas Panhandle, a new discovery in the Atoka formation was established and exploited in 2008. EOG holds approximately 100,000 net acres in the play. To date, 37 horizontal wells have been drilled with initial production rates up to 7.0 MMcfd of natural gas. Plans for 2009 are to continue exploiting these growth areas while pursuing other exploration prospects throughout the Mid-Continent area. EOG holds approximately 500,000 net acres in the Mid-Continent area.

EOG's South Texas and Gulf of Mexico areas had another successful year in 2008, drilling 89 net wells. South Texas and Gulf of Mexico net production averaged 207 MMcfd of natural gas and 6.8 MBbld of crude oil and condensate and natural gas liquids during 2008. EOG's activity was focused in Webb, Zapata, San Patricio, Duval and Matagorda counties, where EOG drilled successful wells in the Lobo, Roleta, Frio and Wilcox trends. EOG's application of horizontal drilling technology in South Texas continues to increase, and the percentage of horizontal wells drilled in the area significantly increased in 2008. A number of additional trends will be exploited with the application of horizontal drilling in 2009. Production from two deepwater Gulf of Mexico wells, drilled in the Atwater Valley area, began in February 2008 at a peak rate of 117 MMcfd of natural gas, gross and 19 MMcfd, net to EOG. Approximately 68 net wells are planned during 2009 for South Texas and the Gulf of Mexico where EOG holds approximately 580,000 net acres.

During 2008, EOG drilled and participated in 48 net wells in the Permian Basin. Twenty-nine net wells were drilled in New Mexico, of which 20 were drilled in the Wolfcamp horizontal play, and the others were drilled in the Morrow, Bone Spring and Permo-Penn formations. Nineteen net wells were drilled in West Texas in multiple objectives. Net production averaged 79 MMcfd of natural gas and 6.8 MBbld of crude oil and condensate and natural gas liquids. Several new oil projects were identified and acreage assembled for testing in 2009. Over 330 square miles of 3-D seismic were acquired in 2008 to assist with these new projects. With the addition of 97,500 acres in 2008, EOG now has approximately 540,000 net acres in the Permian Basin. EOG expects to remain active in the Permian Basin in 2009 and will pursue several exploration prospects in these same areas.

The Upper Gulf Coast continued to be a growth area for EOG where 2008 net production grew 6% year over year and averaged 146 MMcfd of natural gas and 3.1 MBbld of crude oil and condensate and natural gas liquids. EOG drilled 62 net wells with 36 net wells in the Cotton Valley and Travis Peak development programs located in East Texas and North Louisiana, at the Sligo, Driscoll, Appleby, and Waterman fields. Mississippi remained a growth area where 26 net wells were drilled in 2008 and horizontal development of the Selma Chalk at the Gwinville Field was also successful. EOG is further expanding horizontal drilling programs in this area with the development of approximately 116,000 net acres in the emerging Haynesville play where EOG is currently drilling its third horizontal well. EOG holds approximately 350,000 net acres in the Upper Gulf Coast area.

In February 2008, EOG completed the sale of approximately 2,400 shallow Devonian wells with net production of 17 MMcfd of natural gas in the Appalachian Basin. EOG retained the deep rights on the acreage involved in the sale. During the second half of the year, the focus was entirely on evaluating the Marcellus Shale, drilling six horizontal and three vertical wells. These wells tested acreage blocks in Bradford County, Pennsylvania, as well as blocks in the Seneca Resources Joint Venture in North Central Pennsylvania. EOG has tested wells in each of these areas that initially flowed at rates in excess of 3 MMcfd of natural gas. Plans for 2009 include the drilling of 14 gross wells (both horizontal and vertical) and developing the infrastructure necessary to market the gas from the drilling program. EOG holds approximately 220,000 net acres in this area.

At December 31, 2008, EOG held approximately 3,646,000 net undeveloped acres in the United States.

During 2008, EOG continued the growth of its gathering and processing activities in the Barnett Shale play of North Texas and the Bakken Shale play of North Dakota. In 2008, EOG placed into operation one natural gas processing plant in North Dakota, and constructed a second plant in North Texas that came online in early 2009. EOG installed an additional gathering system in the Barnett Combo play of North Texas to transport production to its processing plant and continued expansion of its system in the Bakken Shale play of North Dakota. The North Texas systems total over 70 miles of 8-inch, 10-inch and 20-inch diameter pipe, while the North Dakota system totals over 100 miles of 8-inch pipe. At year-end 2008, the combined throughput of these systems was 56 MMcfd of natural gas.

EOG expects to continue expanding these facilities to accommodate the drilling activity in the Barnett Shale and Bakken Shale plays. In the North Dakota Bakken Shale play, EOG received confirmation from the Federal Energy Regulatory Commission (FERC) on January 12, 2009, to install an approximately 80-mile, 12-inch diameter "dense phase" gas gathering pipeline connecting its Stanley, North Dakota gathering system with the Alliance Pipeline, near Upham, North Dakota, with start-up planned for the third quarter of 2009. The Alliance Pipeline transports natural gas to major markets in Chicago, Illinois. As a part of that project, EOG expects to replace its 20 MMcfd natural gas liquids processing plant, located near Stanley, North Dakota, with an 80 MMcfd refrigeration oil/condensate removal plant during the second quarter of 2009. In combination, these projects will allow EOG to efficiently transport the associated natural gas and natural gas liquids production from its Bakken oil wells.

Canada. EOG conducts operations through its subsidiary, EOG Resources Canada Inc. (EOGRC), from offices in Calgary, Alberta. During 2008, EOGRC continued with its shallow gas strategy in Western Canada, drilling a total of 474 net wells. Key producing areas are the Southeast Alberta/Southwest Saskatchewan shallow gas trends (including the Drumheller, Twining and Halkirk areas), the Pembina/Highvale area of Central Alberta, the Grande Prairie/Wapiti area of Northwest Alberta and the Waskada area of Southwest Manitoba. During 2008, increased capital was directed to oil development projects principally at the Waskada and Highvale large legacy fields, which were initially developed with vertical wells resulting in low recoveries. Horizontal drilling, coupled with specific zone targeting, along with new completion techniques, have yielded favorable results. As a result, EOG plans large field-scale redevelopments for 2009 and beyond.

In the Horn River Basin of Northeastern British Columbia, EOGRC drilled three vertical and five horizontal wells during 2008 and concluded completion operations on two horizontal wells drilled in 2007. Initial gas sales began in July 2008 and currently EOGRC has seven producing wells. Plans for 2009 include drilling seven horizontal wells to further test EOGRC's net acre position.

In 2008, total Canadian net production averaged 222 MMcfd of natural gas and 3.7 MBbld of crude oil and condensate and natural gas liquids. EOGRC plans to drill approximately 180 net wells in 2009.

At December 31, 2008, EOGRC held approximately 1,655,000 net undeveloped acres in Canada.

Operations Outside the United States and Canada

EOG has operations in Trinidad, in the United Kingdom North Sea and in the China Sichuan Basin, and is evaluating additional exploration, development and exploitation opportunities in those 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 SECC Block, except in the Deep Ibis area in which EOG's working interest decreased as a result of a farm-out agreement with BP Trinidad Tobago LLC. In the SECC Block, the Kiskadee, Ibis, Parula and Oilbird fields have been developed and are producing. 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 discussed below. 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, has been developed and is producing.

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. In the second quarter of 2008, EOG relinquished its rights to the LRL Block.

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 adjacent to the SECC Block. EOG holds a 100% working interest in the Modified U(b) Block. 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. At October 2008, 3.7% of the original contract area has been retained for the development of the Oilbird field unit while 12.5% has been retained for further exploration.

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 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 is currently constructing the offshore facilities. From its first discovery on Block 4(a), EOG expects to supply approximately 100 MMcfd, gross (82 MMcfd, net based on current pricing and operating assumptions) in early 2011 under a natural gas contract with the National Gas Company of Trinidad and Tobago (NGC), provided that the pipeline is completed by NGC. The contract is for a term of 15 years with a designated start date of January 1, 2010. EOG expects to begin delivery under this contract in early 2010 and shall initially source the natural gas from its existing fields until the NGC pipeline and development of Block 4(a) are completed. Since the net revenue interest is different on the existing fields, EOG's net deliveries would be 70 MMcfd, based on current pricing and operating assumptions until deliveries begin from Block 4(a).

In the first quarter of 2008, EOG, through its subsidiary, EOGRT, purchased an 80% working interest in the exploration and production license covering the Pelican field and its related facilities (Pelican License) from Trinidad and Tobago Marine Petroleum Company Limited, a subsidiary of the other participants in the SECC Block. The acquisition includes the subsurface rights, offshore facilities, the condensate transport line and the onshore storage facilities. The Pelican License will expire in December 2029.

EOG, through its subsidiary, EOGRT, owns a 12% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited (CNCL). 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 2008, EOG recognized equity income of $7 million and received cash dividends of $1 million from CNCL.

EOG, through its subsidiary, EOG Resources NITRO2000 Ltd. (EOGNitro2000), owns a 10% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited (N2000). 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 2008, EOG recognized equity income of $12 million and received cash dividends of $8 million from N2000.

Natural gas from EOG's Trinidad operations is sold to either NGC or its subsidiary under five gas sales contracts. Approximately 380 MMcfd, gross (225 MMcfd, net) are sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes (approximately 30 MMcfd, gross, 12 MMcfd, net) are sold under a contract for use in the Atlantic LNG Train 4 (ALNG) plant 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 2009.

In October 2008, EOG finalized crude oil and condensate sales contracts with the Petroleum Company of Trinidad and Tobago. The pricing terms are based on the valuation of the distillation yield of the crude oil and condensate produced less a refining margin.

In 2008, EOG's average net production from Trinidad was 218 MMcfd of natural gas and 3.2 MBbld of crude oil and condensate.

At December 31, 2008, EOG held approximately 156,000 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. There are currently two producing wells in the Arthur field, one or both of which could cease production during the second half of 2009.

In 2006, EOGUK participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. A successful Columbus prospect appraisal well was drilled during the third quarter of 2007. The field operator submitted a field development plan to the Department of Energy and Climate Change during the fourth quarter of 2008. EOGUK also participated in the drilling of an unsuccessful exploratory well in August 2007 on the Eos prospect located in the Southern North Sea Block 48/11c.

In the fourth quarter of 2008, EOGUK was awarded three Central North Sea operated licenses in the U.K. 25th Seaward Licensing Round. A rig was contracted to drill two operated wells in the East Irish Sea in 2009. The licenses for the East Irish Sea were awarded to EOG in 2007.

In 2008, EOG delivered net average production of 12 MMcfd of natural gas in the United Kingdom.

At December 31, 2008, EOG held approximately 249,000 net undeveloped acres in the United Kingdom.

China. In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuanzhong Block exploration area in the Sichuan Basin, Sichuan Province, The People's Republic of China. The acquisition includes production of approximately 9 MMcfed, net, on approximately 130,000 acres. In October 2008, EOG obtained the rights to an additional zone on the acreage purchased. EOG plans to drill its first horizontal well in 2009.

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 2008, 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 2009. In 2008, 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 2009. In 2008, all of the wellhead natural gas volumes from China were sold under a contract with prices based on the purchaser's pipeline sales prices to various local market segments. The pricing mechanism for the contract in China is expected to remain the same in 2009.

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

In certain instances, EOG purchases natural gas production from third parties under buy/sell or other arrangements in order to balance firm transportation capacity with production in certain areas.

During 2008, 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.

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 which are determined using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil and condensate or natural gas liquids delivered during each of the years ended December 31, 2008, 2007 and 2006.

Year Ended December 31	**2008**	**2007**	**2006**
Natural Gas Volumes (MMcfd) (1)			
United States	1,162	971	817
Canada	222	224	226
Trinidad	218	252	264
Other International (2)	17	23	30
Total	**1,619**	**1,470**	**1,337**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	39.5	24.6	20.7
Canada	2.7	2.4	2.5
Trinidad	3.2	4.1	4.8
Other International (2)	0.1	0.1	0.1
Total	**45.5**	**31.2**	**28.1**
Natural Gas Liquids Volumes (MBbld) (1)			
United States	15.0	11.1	8.5
Canada	1.0	1.1	0.8
Total	**16.0**	**12.2**	**9.3**
Natural Gas Equivalent Volumes (MMcfed) (3)			
United States	1,490	1,184	992
Canada	244	245	246
Trinidad	237	276	292
Other International (2)	17	24	31
Total	**1,988**	**1,729**	**1,561**
Total Bcfe (3)	**727.6**	**631.3**	**569.9**
Average Natural Gas Prices ($/Mcf) (4)			
United States	$ 8.22	$ 6.27	$ 6.52
Canada	7.64	6.25	6.41
Trinidad	3.58	2.71	2.44
Other International (2)	8.18	6.19	7.69
Composite	**7.51**	**5.65**	**5.72**
Average Crude Oil and Condensate Prices ($/Bbl) (4)			
United States	$ 87.68	$ 68.85	$ 62.68
Canada	89.70	65.27	57.32
Trinidad	92.90	69.84	63.87
Other International (2)	99.30	66.84	57.74
Composite	**88.18**	**68.69**	**62.38**
Average Natural Gas Liquids Prices ($/Bbl) (4)			
United States	$ 53.33	$ 47.63	$ 39.95
Canada	54.77	44.54	43.69
Composite	**53.42**	**47.36**	**40.25**

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil and condensate and natural gas liquids.
(4) Dollars per thousand cubic feet or per barrel, as applicable.

Competition

EOG competes with major integrated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market natural gas and crude oil. Moreover, many of EOG's competitors have financial and other resources substantially greater than those EOG possesses and have established strategic long-term positions and strong governmental relationships in countries in which EOG may seek new or expanded entry. As a consequence, EOG may be at a competitive disadvantage in bidding for drilling rights. In addition, many of EOG's 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 and the cost and availability of alternative fuels. EOG also faces competition from competing energy sources, such as liquefied natural gas imported into the United States from other countries, and, to a lesser extent, alternative energy sources.

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, regulate environmental and safety matters and regulate the calculation and disbursement of royalty payments, production taxes and ad valorem taxes.

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 additional 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 and 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. These statutes are administered by the 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 EOG cannot predict what effect, if any, such legislation might have on its operations and financial condition, 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 and the federal and state regulatory commissions and 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, state, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. EOG is also aware of legislation proposed by United States lawmakers to reduce GHG emissions. Any direct and indirect costs of these regulations may adversely affect EOG's business, results of operations and financial condition. 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 its business and operations 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 crude 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 economic, political or other factors. The implementation of new regulations or the modification of existing regulations affecting the crude 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's 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 system in Canada is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from freehold 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. Royalties payable on lands that the Crown has an interest in 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 and quality of the petroleum product produced. From time to time, the federal and provincial governments of Canada have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing our revenues, earnings and cash flow.

The Alberta Government implemented a new crude oil and natural gas royalty framework effective January 2009. The new framework establishes new royalties for conventional crude 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 crude oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional crude oil range from 0% to 50% and natural gas royalty rates range from 5% to 50%.

The Deep Oil Exploration Program (DOEP) and the Natural Gas Deep Drilling Program (NGDDP) are new programs that began January 1, 2009 in Alberta. These programs provide upfront royalty adjustments to new wells. To qualify for royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 meters with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first 1,000,000 Canadian dollars of royalty or the first 12 months of production. The NGDDP applies to wells producing at a vertical depth greater than 2,500 meters. The NGDDP will have an escalating royalty credit in line with progressively deeper wells from 625 Canadian dollars per meter to a maximum of 3,750 Canadian dollars per meter. There are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five-year programs. Any wells spudded after December 31, 2013, or any wells for which EOG chooses the transition option described below, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional crude oil wells at depths between 1,000 and 3,500 meters, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election is made prior to the end of the first calendar month in which the commodity is produced. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

EOG expects these regulations of the Alberta Government to have a marginally positive impact on EOG's financial condition and results of operations.

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. The Canadian federal government has indicated an intention to regulate industrial emissions of GHG and air pollutants from a broad range of industrial sectors in the Regulatory Framework for Air Emissions released April 2007 and updated in a March 2008 document entitled Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, Federal Plan). The Federal Plan outlines proposed policies to reduce the emissions of GHG and air pollutants 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 Federal Plan also proposes a credit emissions trading system. Additionally, regulation can take place at the provincial and municipal level. For example, the Alberta Government regulates GHG emissions under the Climate Change and Emissions Management Act, the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements, and the Specified Gas Emitters Regulation, which imposes GHG emissions limits. Any 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, the United Kingdom and China.

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 and 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 30% increase in the average wellhead natural gas price for production in the United States and Canada received by EOG from 2007 to 2008, a decrease of 4% from 2006 to 2007, and a decrease of 15% from 2005 to 2006. The average New York Mercantile Exchange (NYMEX) natural gas price strip for 2009 has declined approximately 15% subsequent to December 31, 2008. Crude oil and condensate and natural gas liquids production comprised a larger portion of EOG's product mix in 2008 than in prior years and is expected to increase further in 2009. Average crude oil and condensate prices received by EOG for production in the United States increased by 27% in 2008, 10% in 2007 and 15% in 2006, each as compared to the immediately preceding year. The average NYMEX crude oil price strip for 2009 has declined approximately 10% subsequent to December 31, 2008. Due to the many uncertainties associated with the world political environment, the availabilities of other worldwide 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 ITEM 1A. Risk Factors.

Including the impact of EOG's 2009 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2009 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 $17 million for net income and $25 million for operating cash flow. EOG's price sensitivity in 2009 for each $1.00 per barrel change in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $14 million for net income and $21 million for operating cash flow. For information regarding EOG's natural gas hedge position as of December 31, 2008, 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, price swap and basis 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, 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. EOG's onshore and offshore operations are subject to usual customary 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 these 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 25, 2009) are as follows:

Name	Age	Position
Mark G. Papa	62	Chairman of the Board and Chief Executive Officer; Director
Loren M. Leiker	55	Senior Executive Vice President, Exploration
Gary L. Thomas	59	Senior Executive Vice President, Operations
Robert K. Garrison	56	Executive Vice President, Exploration
Fredrick J. Plaeger, II	55	Senior Vice President and General Counsel
Timothy K. Driggers	47	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.

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, results of operations or cash flow 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 and 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 and condensate or natural gas liquids. Among the factors that can cause these price fluctuations are:

- the level of consumer demand;
- supplies of natural gas and crude oil;
- weather conditions;
- domestic and international drilling activity;
- the price and availability of competing energy sources, including liquefied natural gas;
- the availability, proximity and capacity of transportation facilities;
- worldwide economic and political conditions;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- the effect of worldwide energy conservation measures; and
- the nature and extent of governmental regulation and taxation, including environmental regulations.

Our cash flow and results of operations depend to a great extent on the prevailing prices for natural gas and crude oil. Prolonged or substantial declines in natural gas and/or crude oil prices may materially and adversely affect our liquidity, the amount of cash flow we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

In addition, if we expect significant sustained decreases in natural gas and crude oil prices in the future such that the future cash flow from our natural gas and crude oil properties falls below the net book value of our properties, we may be required to write down the value of our natural gas and crude oil properties. Any such future asset impairments could materially and adversely affect our results of operations and, in turn, the trading price of our common stock.

Drilling natural gas and crude oil wells is a high-risk activity and subjects us to a variety of risks 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.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators 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;
- the availability and timely issuance of required governmental permits and licenses;
- the availability of, costs associated with and terms of contractual arrangements for properties, including leases, pipelines and related facilities and equipment to gather, process, compress, transport and market natural gas, crude oil and related commodities;
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and other necessary equipment; and
- lack of necessary services and/or qualified personnel.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators may materially and adversely affect our business, financial condition and results of operations.

Our ability to sell and deliver our natural gas and crude oil production could be materially and adversely affected if we fail to obtain adequate gathering, processing, compression and transportation services.

The sale of our natural gas and crude oil production depends on a number of factors beyond our control, including the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities owned by third parties. These facilities may be temporarily unavailable to us due to market conditions, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. Any significant change in market or other conditions affecting these facilities or the availability of these facilities, including due to 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.

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

The rate of production from natural gas and crude oil properties generally declines as reserves are depleted. Except to the extent that we conduct successful exploration. exploitation 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. Maintaining our production of natural gas and crude oil at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves, as is, in turn, our future cash flow and results of operations.

A portion of our natural gas and crude oil production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our natural gas and crude oil production may be interrupted, or shut in, from time to time for various reasons, including as a result of accidents, weather conditions, loss of gathering, processing, compression or transportation facility access or field labor issues, or intentionally as a result of market conditions such as natural gas or crude oil prices that we deem uneconomic. If a substantial amount of our production is interrupted, our cash flow and, in turn, our results of operations could be materially and adversely affected.

We operate in other countries and, as a result, are subject to certain political, economic and other risks.

Our operations in jurisdictions outside the United States (U.S.) are subject to various risks inherent in foreign operations. These risks may include, among other risks:

- loss of revenue, equipment and property as a result of expropriation, war and other political risks;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- changes in laws and policies governing operations of foreign-based companies; and
- currency restrictions and exchange rate fluctuations.

Our international operations may also be adversely affected by U.S. laws and policies affecting foreign trade and taxation. The realization of any of these factors could materially and adversely affect our business, financial condition and results of operations.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

If we acquire natural gas and crude oil properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties 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 in a manner that we believe is consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may 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 may 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 our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

Weather and climate may have a significant and adverse impact on us.

Demand for natural gas and crude oil is, to a significant degree, dependent on weather and climate, which impacts, among other things, the price we receive for the commodities we produce and, in turn, our cash flow and results of operations. For example, relatively warm temperatures during a winter season generally result in relatively lower demand for natural gas (as less natural gas is used to heat residences and businesses) and, as a result, relatively lower prices for natural gas production.

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, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and 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, the installation and operation of gathering and production facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation. Such extreme weather conditions could materially and adversely affect our business and, in turn, our financial condition and results of operations.

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

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, commercial paper borrowings and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facilities 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 credit and capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable, if at all. The recent credit crisis and corresponding reaction by lenders to risk and, related thereto, the recent weakness and volatility in domestic and global financial markets and economic conditions, may increase the interest rates that lenders and commercial paper investors require us to pay and adversely affect our ability to finance our capital expenditures through equity or debt offerings. 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.

The inability of our customers and other contractual counterparties to satisfy their obligations to us may have a material and adverse effect on us.

We have various customers for the natural gas, crude oil and related commodities that we produce as well as various other contractual counterparties, including several financial institutions and affiliates of financial institutions. Domestic and global economic conditions, including the financial condition of financial institutions generally, have recently weakened. In addition, there has been recent weakness and volatility in domestic and global financial markets, including the credit crisis and corresponding reaction by lenders to risk. These conditions and factors may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes.

Moreover, our customers and other contractual counterparties may be unable to satisfy their contractual obligations to us for reasons unrelated to these conditions and factors, such as the unavailability of required facilities or equipment due to mechanical failure or market conditions. Furthermore, if a customer is unable to satisfy its contractual obligation to purchase natural gas, crude oil or related commodities from us, we may be unable to sell such production to another customer on terms we consider acceptable, if at all, due to the geographic location of such production, the availability, proximity or capacity of transportation facilities or market or other factors and conditions.

The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us may materially and adversely affect our business, financial condition, results of operations and cash flow.

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 oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market natural gas and crude oil. 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 and the cost and availability of alternative fuels. We also face competition from competing energy sources, such as liquefied natural gas imported into the U.S. from other countries and, to a lesser extent, alternative energy sources.

Reserve estimates depend on many interpretations and assumptions that may turn out to be inaccurate. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities of our reserves to be materially misstated.

Estimating quantities of proved natural gas and liquids 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, made by our management and our independent petroleum consultants. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Moreover, 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.

To prepare estimates of our economically recoverable natural gas and liquids 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 materially and adversely affect our business, financial condition and results of operations and the trading price of our common stock.

We incur certain costs to comply with government regulations, particularly regulations relating to environmental protection and safety, 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 the foreign countries in which we do business, and are subject to interruption or termination by governmental and regulatory authorities based on environmental or other considerations. Moreover, we have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, safety 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 and, in turn, materially and adversely affect our business, financial condition and results of operations.

Specifically, 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 the discharge of materials into, and the 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, these regulations could materially and adversely affect our business, financial condition and results of operations.

EOG is aware of the increasing focus of local, state, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. We are also aware of legislation proposed by U.S. lawmakers and by the Canadian legislature to reduce 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. Any direct and indirect costs of these regulations may materially and adversely affect EOG's business, results of operations and financial condition.

Our hedging activities may prevent us from benefiting fully from increases in natural gas and crude oil prices and may expose us to other risks, including counterparty risk.

We use derivative instruments (primarily financial collars, price swaps and basis swaps) to hedge the impact of fluctuations in natural gas and crude oil prices on our results of operations and cash flow. To the extent that we engage in hedging activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of increases in natural gas and crude oil prices above the prices established by our hedging contracts. In addition, our hedging activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

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 onshore and offshore operations are subject to customary perils, including hurricanes and other adverse weather conditions. 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 our exploration, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Our business and prospects for future success depend to a significant extent upon the continued service and performance of our management team.

Our business and prospects for future success, including the successful implementation of our strategies and handling of issues integral to our future success, depend to a significant extent upon the continued service and performance of our management team. The loss of any member of our management team, and our inability to attract, motivate and retain substitute management personnel with comparable experience and skills, could materially and adversely affect 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 U.S. 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 amount 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, 2008, approximately 11% of our revenues related to operations of our foreign subsidiaries whose functional currency was not the U.S. dollar.

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 U.S. government has at times issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. Any such actions could materially and adversely affect us in unpredictable ways, including the disruption of energy 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, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

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 and condensate and natural gas liquids, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in Supplemental Information to Consolidated Financial Statements represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, crude oil and 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, the rate of 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, conducts successful exploration, exploitation and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, 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. For related discussion, see ITEM 1A. Risk Factors. EOG's estimates of reserves filed with other federal agencies agree with the information set forth in Supplemental Information to Consolidated Financial Statements.

Acreage. The following table summarizes EOG's developed and undeveloped acreage at December 31, 2008. 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	1,555,136	1,129,626	4,986,221	3,645,805	6,541,357	4,775,431
Canada	1,957,454	1,662,253	2,104,571	1,654,909	4,062,025	3,317,162
Trinidad	72,901	64,286	165,427	155,723	238,328	220,009
United Kingdom	10,230	2,946	483,012	249,102	493,242	252,048
China (1)	130,546	130,546	-	-	130,546	130,546
Total	3,726,267	2,989,657	7,739,231	5,705,539	11,465,498	8,695,196

(1) EOG's China operations were acquired effective July 1, 2008.

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, the United Kingdom and China at December 31, 2008. Gross natural gas and crude oil wells include 2,380 with multiple completions.

	Productive Wells	
	Gross	**Net**
Natural Gas	21,524	17,992
Crude Oil	1,944	1,294
Total	23,468	19,286

Drilling and Acquisition Activities. During the years ended December 31, 2008, 2007 and 2006, EOG expended $5.1 billion, $3.6 billion and $2.9 billion, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of $181 million, $31 million and $22 million, respectively. EOG drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
United States and Canada						
Gas	1,498	1,261	1,747	1,441	2,240	1,922
Oil	223	171	98	86	60	50
Dry	50	47	59	52	66	57
Total	1,771	1,479	1,904	1,579	2,366	2,029
Outside United States and Canada						
Gas	-	-	6	5	1	-
Oil	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	-	-	6	5	1	-
Total Development	1,771	1,479	1,910	1,584	2,367	2,029
Exploratory Wells Completed						
United States and Canada						
Gas	44	38	62	54	53	45
Oil	37	19	14	12	2	2
Dry	9	9	18	16	21	17
Total	90	66	94	82	76	64
Outside United States and Canada						
Gas	-	-	-	-	2	2
Oil	-	-	-	-	-	-
Dry	-	-	2	1	-	-
Total	-	-	2	1	2	2
Total Exploratory	90	66	96	83	78	66
Total	1,861	1,545	2,006	1,667	2,445	2,095
Wells in Progress at end of period	223	191	223	195	221	180
Total	2,084	1,736	2,229	1,862	2,666	2,275
Wells Acquired (1)						
Gas	102	94	41	15	114	106
Oil	9	7	-	-	1	1
Total	111	101	41	15	115	107

(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 contractual basis with independent drilling contractors. EOG does not own 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 2008.

PART II

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

EOG's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "EOG." The following table sets forth, for the periods indicated, the high and low sales price per share for EOG's common stock, as reported by the NYSE, and the amount of the cash dividend declared per share.

	Price Range		
	High	Low	Dividend Declared
2008			
First Quarter	$ 129.90	$ 77.18	$ 0.120
Second Quarter	144.99	117.76	0.120
Third Quarter	133.89	79.80	0.135
Fourth Quarter	90.80	54.42	0.135
2007			
First Quarter	$ 73.09	$ 59.21	$ 0.090
Second Quarter	81.49	71.15	0.090
Third Quarter	76.92	65.29	0.090
Fourth Quarter	91.63	72.20	0.090

On February 7, 2008, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the previous $0.09 per share to $0.12 per share effective beginning with the dividend paid on April 30, 2008 and on July 29, 2008, increased the quarterly cash dividend on the common stock from the previous $0.12 per share to $0.135 per share effective beginning with the dividend paid on October 31, 2008.

On February 4, 2009, EOG's Board increased the quarterly cash dividend on the common stock from the previous $0.135 per share to $0.145 per share effective beginning with the dividend to be paid on April 30, 2009.

As of February 18, 2009, there were approximately 450 record holders and approximately 295,000 beneficial owners of EOG's common stock.

EOG currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock in the future. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other factors, the financial condition, cash flow, level of exploration 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, 2008 - October 31, 2008	138	$84.35	-	6,386,200
November 1, 2008 - November 30, 2008	83,705	77.13	-	6,386,200
December 1, 2008 - December 31, 2008	1,420	70.67	-	6,386,200
Total	85,263	77.03		

(1) The 85,263 total shares for the quarter ended December 31, 2008 and the 194,761 shares for the full year 2008 consist solely of shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share authorization of EOG's Board discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2008, EOG did not repurchase any shares under the Board-authorized repurchase program.

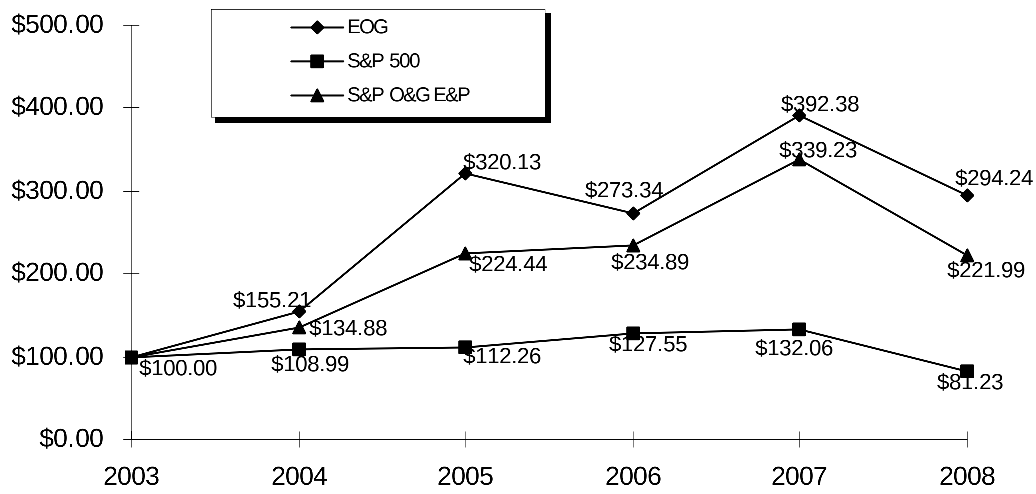
Comparative Stock Performance

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 requests that such information be treated as "soliciting material" or 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 five-year 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, 2003 in each of the following: 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, 2008)



	2003	**2004**	**2005**	**2006**	**2007**	**2008**
EOG	$100.00	$155.21	$320.13	$273.34	$392.38	$294.24
S&P 500	$100.00	$108.99	$112.26	$127.55	$132.06	$ 81.23
S&P O&G E&P	$100.00	$134.88	$224.44	$234.89	$339.23	$221.99

ITEM 6. ***Selected Financial Data***
(In Thousands, Except Per Share Data)

Year Ended December 31	**2008**	**2007**	**2006**	**2005**	**2004**
Statement of Income Data:					
Net Operating Revenues (1)	$ 7,127,143	$ 4,239,303	$ 3,928,641	$ 3,671,243	$ 2,308,146
Operating Income	$ 3,767,185	$ 1,648,396	$ 1,903,553	$ 2,004,631	$ 985,148
Net Income	$ 2,436,919	$ 1,089,918	$ 1,299,885	$ 1,259,576	$ 624,855
Preferred Stock Dividends	443	6,663	10,995	7,432	10,892
Net Income Available to Common Stockholders	$ 2,436,476	$ 1,083,255	$ 1,288,890	$ 1,252,144	$ 613,963
Net Income Per Share Available to Common Stockholders (2)					
Basic	$ 9.88	$ 4.45	$ 5.33	$ 5.24	$ 2.63
Diluted	$ 9.72	$ 4.37	$ 5.24	$ 5.13	$ 2.58
Dividends Per Common Share(2)	$ 0.51	$ 0.36	$ 0.24	$ 0.16	$ 0.12
Average Number of Common Shares(2)					
Basic	246,662	243,469	241,782	238,797	233,751
Diluted	250,542	247,637	246,100	243,975	238,376

(1) Certain reclassifications have impacted Net Operating Revenues. See Note 1 to Consolidated Financial Statements.
(2) Year 2004 restated for two-for-one stock split effective March 1, 2005.

At December 31	**2008**	**2007**	**2006**	**2005**	**2004**
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 13,657,302	$ 10,429,254	$ 7,944,047	$ 6,087,179	$ 5,101,603
Total Assets	15,951,226	12,088,907	9,402,160	7,753,320	5,798,923
Long-Term Debt and Current Portion of Long-Term Debt	1,897,000	1,185,000	733,442	985,067	1,077,622
Total Stockholders' Equity	9,014,497	6,990,094	5,599,671	4,316,292	2,945,424

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, Trinidad, the United Kingdom North Sea and China. 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 2008 of $2,436 million was up 125% compared to 2007 net income available to common stockholders of $1,083 million. At December 31, 2008, EOG's total reserves were 8.7 trillion cubic feet equivalent, an increase of 944 billion cubic feet equivalent (Bcfe) from December 31, 2007.

Operations

Several important developments have occurred since January 1, 2008.

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 87% of total company production in 2008 as compared to 83% in 2007. In 2008, the Fort Worth Basin Barnett Shale and North Dakota Bakken areas produced an increasing amount of crude oil and natural gas liquids. For 2008, crude oil and natural gas liquids production accounted for approximately 19% of total company production as compared to 15% for 2007. Based on current trends, EOG expects its 2009 crude oil and natural gas liquids production to increase as compared to 2008. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

In February 2008, EOG closed on the sale of 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 $386 million ($40 million of which was received in 2007). The Appalachian area that was divested included 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. EOG retained certain of its undeveloped acreage in this area, including rights in the Marcellus Shale, and continued its shale exploration program in 2008.

In the third quarter of 2008, EOG commenced production in its British Columbia, Canada shale gas play. EOG holds approximately 158,000 net acres in this play at December 31, 2008 and expects to slowly increase production until 2012, when the construction of additional infrastructure for the play is expected to be completed.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. In February 2008, EOG, through its subsidiary EOG Resources Trinidad Limited (EOGRT) purchased an 80% working interest in the exploration and production license covering the Pelican field and its related facilities from Trinidad and Tobago Marine Petroleum Company Limited. The acquisition includes the subsurface rights, offshore facilities, the condensate transport line and the onshore storage facilities.

In October 2008, EOG, through its subsidiaries, EOGRT, EOG Resources Trinidad-U(a) Block Limited and EOG Resources Trinidad U(b) Block Unlimited (EOGRT U(b)), finalized crude oil and condensate sales contracts with the Petroleum Company of Trinidad and Tobago. The pricing terms are based on the valuation of the distillation yield of the crude oil and condensate produced less a refining margin.

In April 2008, EOG's subsidiary, EOG Resources Trinidad-LRL Unlimited, relinquished its rights to Lower Reverse "L" Block and recorded an impairment of $20 million. In December 2008, EOG, through its subsidiaries EOGRT and EOGRT U(b), began production from the Oilbird field.

EOG continues to expand its exploration prospect portfolio in the United Kingdom (U.K.) in addition to its ongoing production from the Valkyrie and Arthur fields in the Southern Gas Basin of the North Sea Block 23/16f. There are currently two producing wells in the Arthur field, one or both of which could cease production during the second half of 2009. During the fourth quarter of 2008, EOG recorded an impairment of $6 million ($3 million after-tax) for its Arthur field based on well performance. During 2008, a field development plan was submitted for the Columbus discovery in the Central North Sea. In the fourth quarter of 2008, EOGUK was awarded three Central North Sea operated licenses in the U.K. 25th Seaward Licensing Round. A rig was contracted to drill two operated wells in the East Irish Sea in 2009. The licenses for the East Irish Sea were awarded to EOG in 2007.

In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuanzhong Block exploration area in the Sichuan Basin, Sichuan Province, The People's Republic of China. The acquisition includes production of approximately 9 million cubic feet equivalent per day, net, on approximately 130,000 acres. In October 2008, EOG obtained the rights to additional zones on the acreage purchased. EOG plans to drill its first horizontal well in 2009.

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, 2008, EOG's debt-to-total capitalization ratio was 17%. During 2008, EOG funded $5.4 billion in exploration and development and other property, plant and equipment expenditures, paid $115 million in dividends to common and preferred stockholders, repaid $38 million of debt and paid $5 million for the redemption of all remaining 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), primarily by utilizing cash provided from its operating activities, proceeds from long-term debt borrowings and proceeds from the sale of its Appalachian assets.

For 2009, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $3.1 billion, excluding acquisitions. United States and Canada crude oil and natural gas drilling activity continues to be a key component of these expenditures. EOG intends to manage the 2009 capital budget in order to balance expenditures with operating cash flows. 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 30, 2008, EOG completed its public offering of $400 million aggregate principal amount of 6.125% Senior Notes due 2013 and $350 million aggregate principal amount of 6.875% Senior Notes due 2018 (collectively, Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning April 1, 2009. Net proceeds from the offering of approximately $743 million were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2008 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2008, net operating revenues increased $2,888 million, or 68%, to $7,127 million from $4,239 million in 2007. Total wellhead revenues, which are revenues generated from sales of EOG's production of natural gas, crude oil and condensate and natural gas liquids, increased $2,202 million, or 55%, to $6,222 million from $4,020 million in 2007. During 2008, EOG recognized net gains on mark-to-market commodity derivative contracts of $598 million compared to net gains of $93 million in 2007. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party natural gas and natural gas liquids as well as gathering fees associated with gathering third-party natural gas, increased $91 million, or 124%, to $165 million in 2008 from $74 million in 2007. Other, net operating revenues in 2008 primarily consist of the gain of $128 million on the sale of the Appalachian assets in February 2008. The following review of operations gives effect to the reclassifications discussed in Note 1 to Consolidated Financial Statements.

Wellhead volume and price statistics for the years ended December 31, 2008, 2007 and 2006 were as follows:

Year Ended December 31	**2008**	**2007**	**2006**
Natural Gas Volumes (MMcfd) [(1)]			
United States	1,162	971	817
Canada	222	224	226
Trinidad	218	252	264
Other International [(2)]	17	23	30
Total	**1,619**	**1,470**	**1,337**
Average Natural Gas Prices ($/Mcf) [(3)]			
United States	$ 8.22	$ 6.27	$ 6.52
Canada	7.64	6.25	6.41
Trinidad	3.58	2.71	2.44
Other International [(2)]	8.18	6.19	7.69
Composite	**7.51**	**5.65**	**5.72**
Crude Oil and Condensate Volumes (MBbld) [(1)]			
United States	39.5	24.6	20.7
Canada	2.7	2.4	2.5
Trinidad	3.2	4.1	4.8
Other International [(2)]	0.1	0.1	0.1
Total	**45.5**	**31.2**	**28.1**
Average Crude Oil and Condensate Prices ($/Bbl) [(3)]			
United States	$ 87.68	$ 68.85	$ 62.68
Canada	89.70	65.27	57.32
Trinidad	92.90	69.84	63.87
Other International [(2)]	99.30	66.84	57.74
Composite	**88.18**	**68.69**	**62.38**
Natural Gas Liquids Volumes (MBbld) [(1)]			
United States	15.0	11.1	8.5
Canada	1.0	1.1	0.8
Total	**16.0**	**12.2**	**9.3**
Average Natural Gas Liquids Prices ($/Bbl) [(3)]			
United States	$ 53.33	$ 47.63	$ 39.95
Canada	54.77	44.54	43.69
Composite	**53.42**	**47.36**	**40.25**
Natural Gas Equivalent Volumes (MMcfed) [(4)]			
United States	1,490	1,184	992
Canada	244	245	246
Trinidad	237	276	292
Other International [(2)]	17	24	31
Total	**1,988**	**1,729**	**1,561**
Total Bcfe [(4)]	727.6	631.3	569.9

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) Dollars per thousand cubic feet or per barrel, as applicable.
(4) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil and 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 and condensate or natural gas liquids.

2008 compared to 2007. Wellhead natural gas revenues in 2008 increased $1,419 million, or 47%, to $4,452 million from $3,033 million for 2007 due to a higher composite average wellhead natural gas price ($1,101 million) and increased natural gas deliveries ($318 million). EOG's composite average wellhead natural gas price increased 33% to $7.51 per Mcf in 2008 from $5.65 per Mcf in 2007.

Natural gas deliveries increased 149 MMcfd, or 10%, to 1,619 MMcfd in 2008 from 1,470 MMcfd in 2007. The increase was due to higher production of 191 MMcfd in the United States and initial production of 5 MMcfd in China, partially offset by lower production of 34 MMcfd in Trinidad, 11 MMcfd in the United Kingdom and 2 MMcfd in Canada. The increase in the United States was primarily attributable to increased production from Texas (140 MMcfd), the Rocky Mountain area (54 MMcfd), Mississippi (8 MMcfd) and Kansas (4 MMcfd), partially offset by decreased production due to the February 2008 sale of the Appalachian assets (15 MMcfd). The decline in Trinidad was primarily due to decreased deliveries as a result of plant shutdowns due to unplanned maintenance activities (29 MMcfd) and reduced deliveries due to lower demand in 2008 (10 MMcfd), partially offset by increased deliveries to Atlantic LNG Train 4 (ALNG) (5 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 $680 million, or 87%, to $1,458 million in 2008 from $778 million in 2007, due to an increase of 14.3 MBbld, or 46%, in wellhead crude oil and condensate deliveries ($358 million) and a higher composite average wellhead crude oil and condensate price ($322 million). The increase in deliveries primarily reflects increased production in North Dakota (12 MBbld). The composite average wellhead crude oil and condensate price for 2008 increased 28% to $88.18 per barrel compared to $68.69 per barrel for 2007.

Natural gas liquids revenues increased $102 million, or 49%, to $312 million in 2008 from $210 million in 2007, due to increases in deliveries ($67 million) and a higher composite average price ($35 million). The composite average natural gas liquids price for 2008 increased 13% to $53.42 per barrel compared to $47.36 per barrel for 2007. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

During 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included realized losses of $137 million. During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included realized gains of $128 million.

Gathering, processing and marketing revenues represent sales of third-party natural gas and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. For the years ended December 31, 2008, 2007 and 2006, substantially all of such revenues were related to sales of third-party natural gas. Marketing costs represent the costs of purchasing third-party natural gas and the associated transportation costs.

Gathering, processing and marketing revenues less marketing costs increased $5 million to $12 million in 2008 compared to $7 million in 2007. The increase resulted primarily from natural gas marketing operations in the Gulf Coast area.

2007 compared to 2006. Wellhead natural gas revenues in 2007 increased $240 million, or 9%, to $3,033 million from $2,793 million in 2006 due to increased natural gas deliveries ($277 million), partially offset by a lower composite average wellhead natural gas price ($37 million). The composite average wellhead natural gas price decreased to $5.65 per Mcf in 2007 from $5.72 per Mcf in 2006.

Natural gas deliveries increased 133 MMcfd, or 10%, to 1,470 MMcfd in 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 in 2007 from $625 million in 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 in 2007 was $68.69 per barrel compared to $62.38 per barrel in 2006.

Natural gas liquids revenues increased $73 million, or 53%, to $210 million in 2007 from $137 million in 2006, due to increases in deliveries ($42 million) and a higher 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.

Gathering, processing and marketing revenues less marketing costs in 2007 increased $4 million to $7 million in 2007 from $3 million in 2006 primarily as a result of increased natural gas marketing operations in the Gulf Coast area.

Operating and Other Expenses

2008 compared to 2007. During 2008, operating expenses of $3,360 million were $769 million higher than the $2,591 million incurred in 2007. The following table presents the costs per Mcfe for the years ended December 31, 2008 and 2007:

		2008		2007
Lease and Well	$	0.77	$	0.72
Transportation Costs		0.38		0.24
Depreciation, Depletion and Amortization (DD&A) -				
Oil and Gas Properties		1.74		1.63
Other Property, Plant and Equipment		0.09		0.06
General and Administrative (G&A)		0.34		0.33
Net Interest Expense		0.07		0.07
Total Per-Unit Costs (1)	**$**	**3.39**	**$**	**3.05**

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2008 as compared to 2007 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 crude oil and natural gas wells, the cost of workovers, and lease and well administrative expenses. Operating and maintenance expenses include, among other expenses, 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 $559 million in 2008 increased $107 million from $452 million in 2007 due primarily to higher operating and maintenance expenses ($78 million) and higher lease and well administrative expenses ($28 million), both in the United States.

Transportation costs represent costs incurred directly by EOG from third-party carriers associated with the delivery of hydrocarbon products from the lease to a downstream 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 $274 million in 2008 increased $122 million from $152 million in 2007 primarily due to increased production and costs associated with marketing arrangements to transport production from the Fort Worth Basin Barnett Shale area ($64 million) and the Rocky Mountain area ($38 million) to 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. DD&A of the cost of other property, plant and equipment is calculated using the straight-line depreciation method over the useful lives of the assets. Other property, plant and equipment consist of natural gas gathering and processing facilities, compressors, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses in 2008 increased $261 million to $1,327 million from $1,066 million in 2007. DD&A expenses associated with oil and gas properties were $236 million higher than in 2007 primarily due to higher unit rates described below and as a result of increased production in the United States ($210 million), partially offset by a decrease in production in the United Kingdom ($10 million) and in Trinidad ($3 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($15 million) and Canada ($8 million). Changes in the Canadian exchange rate ($11 million) also contributed to the DD&A expense increase.

DD&A expenses associated with other property, plant and equipment were $25 million higher in 2008 than in 2007 primarily due to increased expenditures associated with natural gas gathering systems in the Fort Worth Basin Barnett Shale area.

G&A expenses of $244 million in 2008 were $38 million higher than 2007 due primarily to higher employee-related costs ($33 million). The increase in employee-related costs primarily reflects higher stock-based compensation expenses ($18 million).

Net interest expense of $52 million in 2008 increased $5 million from $47 million in 2007 primarily due to a higher average debt balance ($18 million), partially offset by higher capitalized interest ($13 million).

Gathering and processing costs represent operation and maintenance expenses and administrative expenses associated with operating EOG's natural gas gathering and processing assets.

Gathering and processing costs increased $13 million to $41 million in 2008 as compared to $28 million in 2007. The increase primarily reflects increased activities in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

Exploration costs of $194 million in 2008 increased $44 million from $150 million for the same prior year period primarily due to increased geological and geophysical expenditures in the United States ($27 million) and higher employee-related costs ($15 million). The increase in geological and geophysical expenditures in the United States was primarily attributable to activities in the Fort Worth Basin Barnett Shale area ($21 million).

Impairments include amortization of unproved leases, as well as impairments under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), which requires an entity to compute impairments to the carrying value of long-lived assets based on future cash flow analysis. Impairments of $193 million in 2008 were $45 million higher than impairments of $148 million in 2007 due primarily to increased amortization costs as a result of increased leasehold acquisition expenditures in the United States ($30 million) and Canada ($12 million), an SFAS No. 144 related impairment in Trinidad as a result of EOG's relinquishment of its rights to Lower Reverse "L" Block ($20 million) and an SFAS No. 144 related impairment in the United Kingdom for the Arthur field ($6 million), partially offset by decreased SFAS No. 144 related impairments in Canada ($20 million). Under SFAS No. 144, EOG recorded impairments of $86 million and $82 million for 2008 and 2007, 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 2008 increased $113 million to $321 million (5.2% of wellhead revenues) from $208 million (5.2% of wellhead revenues) in 2007 primarily due to an increase in severance/production taxes in the United States as a result of increased wellhead revenues ($86 million), a decrease in credits taken in 2008 for Texas high cost gas severance tax rate reductions ($13 million) and increased ad valorem/property taxes as a result of higher property valuations in the United States ($20 million).

Income tax provision of $1,310 million in 2008 increased $769 million compared to 2007 due primarily to increased pretax income. The net effective tax rate for 2008 increased to 35% from 33% in 2007. The increase in the 2008 net effective tax rate is primarily due to a Canadian federal tax rate reduction in 2007.

2007 compared to 2006. During 2007, operating expenses of $2,591 million were $566 million higher than the $2,025 million incurred in 2006. The following table presents the costs per Mcfe for the years ended December 31, 2007 and 2006:

	2007	2006
Lease and Well	$ 0.72	$ 0.63
Transportation Costs	0.24	0.18
DD&A -		
Oil and Gas Properties	1.63	1.39
Other Property, Plant and Equipment	0.06	0.05
G&A	0.33	0.29
Net Interest Expense	0.07	0.08
Total Per-Unit Costs (1)	**$ 3.05**	**$ 2.62**

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

The primary factors impacting the cost components of 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 of $452 million in 2007 were $96 million higher than 2006 due primarily to higher operating and maintenance expenses in the United States ($53 million) and Canada ($13 million), higher lease and well administrative expenses ($17 million), higher workover expenditures in the United States ($7 million) and changes in the Canadian exchange rate ($7 million).

Transportation costs of $152 million in 2007 were $52 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 expenses in 2007 increased $248 million to $1,066 million from $817 million in 2006. DD&A expenses associated with oil and gas properties were $235 million higher than in 2006 primarily due to higher unit rates described below and as a result of increased production in the United States ($117 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 ($93 million), Canada ($18 million) and in the United Kingdom ($2 million). Changes in the exchange rates in Canada ($10 million) and in the United Kingdom ($1 million) also contributed to the DD&A expense increase.

DD&A expenses associated with other property, plant and equipment were $13 million higher in 2007 than in 2006 primarily due to increased expenditures associated with natural gas gathering systems in the Fort Worth Basin Barnett Shale area.

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).

Gathering and processing costs increased $10 million to $28 million in 2007 as compared to 2006. The increase primarily reflects increased activity in the Fort Worth Basin Barnett Shale area.

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 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 16 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 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.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2008 were funds generated from operations, the issuance of long-term debt, proceeds from stock options exercised and employee stock purchase plan activity, proceeds from the sale of oil and gas properties, excess tax benefits from stock-based compensation, net commercial paper borrowings and borrowings under other uncommitted credit facilities and revolving credit facilities. 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.

2008 compared to 2007. Net cash provided by operating activities of $4,633 million in 2008 increased $1,732 million from $2,901 million in 2007 primarily reflecting an increase in wellhead revenues ($2,202 million); favorable changes in working capital and other assets and liabilities ($170 million); an increase in gathering, processing and marketing revenues ($91 million); and a decrease in cash paid for income taxes ($50 million); partially offset by an increase in cash operating expenses ($404 million); an increase in marketing costs ($86 million); an unfavorable change in the net cash flow from the settlement of financial commodity derivative contracts ($265 million); and an increase in cash paid for interest expense ($9 million).

Net cash used in investing activities of $4,967 million in 2008 increased by $1,511 million from $3,456 million for the same period of 2007 due primarily to an increase in additions to oil and gas properties ($1,317 million), unfavorable changes in working capital associated with investing activities ($296 million) and an increase in additions to other property, plant and equipment ($199 million), partially offset by an increase in proceeds from sales of assets ($300 million), primarily reflecting net proceeds from the sale of EOG's Appalachian assets.

Net cash provided by financing activities was $645 million in 2008 compared to $386 million in 2007. Cash provided by financing activities for 2008 included the issuance of long-term debt ($750 million), proceeds from stock options exercised and employee stock purchase plan activity ($73 million) and excess tax benefits from stock-based compensation ($6 million). Cash used in financing activities during 2008 included cash dividend payments ($115 million), Trinidad revolving credit facility repayment ($38 million), treasury stock purchases ($18 million), debt issuance costs ($8 million) and the redemption of preferred stock ($5 million).

2007 compared to 2006. Net cash provided by operating activities of $2,901 million in 2007 increased $305 million compared to 2006 primarily reflecting an increase in wellhead revenues ($466 million); a decrease in cash paid for income taxes ($157 million); and an increase in gathering, processing and marketing revenues ($44 million); partially offset by an increase in cash operating expenses ($172 million); an increase in marketing costs ($40 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 ($65 million).

Net cash used in investing activities of $3,456 million in 2007 increased by $745 million compared to 2006 due primarily to an increase in additions to oil and gas properties ($652 million) and an increase in additions to other property, plant and equipment ($177 million), partially offset by an increase in proceeds from sales of assets ($63 million).

Net cash provided by financing activities was $386 million in 2007 compared to net cash used in financing activities of $316 million in 2006. Cash provided by financing activities for 2007 included the issuance of long-term debt ($600 million), proceeds from stock options exercised and employee stock purchase plan activity ($55 million), excess tax benefits from stock-based compensation ($27 million) and Trinidad revolving credit facility borrowings ($10 million). Cash used in financing activities for 2007 included repayments of long-term borrowings ($158 million), cash dividend payments ($84 million), redemptions of preferred stock ($51 million), treasury stock purchases ($8 million) and debt issuance costs ($5 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2008, 2007 and 2006, along with the total expenditures budgeted for 2009, excluding acquisitions (in millions):

	Actual			Budgeted 2009
	2008	**2007**	**2006**	**(excluding acquisitions)**
Expenditure Category				
Capital				
Drilling and Facilities	$ 3,990	$ 2,976	$ 2,403	
Leasehold Acquisitions	521	278	225	
Producing Property Acquisitions	109	20	22	
Capitalized Interest	43	29	20	
Subtotal	4,663	3,303	2,670	
Exploration Costs	194	150	155	
Dry Hole Costs	55	115	80	
Exploration and Development Expenditures	4,912	3,568	2,905	Approximately $2,850
Asset Retirement Costs	181	31	22	
Total Exploration and Development Expenditures	5,093	3,599	2,927	
Other Property, Plant and Equipment	477	277	100	Approximately $250
Total Expenditures	**$ 5,570**	**$ 3,876**	**$ 3,027**	

Exploration and development expenditures of $4,912 million for 2008 were $1,344 million higher than the prior year due primarily to increased drilling and facilities expenditures of $1,014 million resulting from higher drilling and facilities expenditures in the United States ($1,064 million), increased lease acquisitions in the United States ($143 million) and Canada ($96 million), increased producing property acquisitions in the United States ($66 million) and Canada ($12 million), increased geological and geophysical expenditures in the United States ($27 million) primarily attributable to the Fort Worth Basin Barnett Shale Play ($21 million), higher exploration employee-related costs ($15 million) and increased capitalized interest in the United States ($11 million). These increases were partially offset by decreased dry hole costs in the United States ($40 million) and Trinidad ($20 million). The 2008 exploration and development expenditures of $4,912 million includes $3,612 million in development, $1,148 million in exploration, $109 million in producing property acquisitions and $43 million in capitalized interest. The increase in expenditures for other property, plant and equipment primarily related to natural gas gathering systems and processing plants in the Fort Worth Basin Barnett Shale and Rocky Mountain areas. 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 producing 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 producing property acquisitions and $20 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, the United Kingdom North Sea and China, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

During 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included realized losses of $137 million. During 2007, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $93 million, which included realized gains of $128 million. See Note 11 to Consolidated Financial Statements.

Financial Collar Contracts. The total fair value of EOG's natural gas financial collar contracts at December 31, 2008 was a positive $44 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at February 25, 2009. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 is $10.00 per million British thermal units (MMBtu) and the average ceiling price is $12.32 per MMBtu.

Natural Gas Financial Collar Contracts					
		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55
July	40,000	9.40 - 9.45	9.43	11.60 - 11.70	11.65
August	40,000	9.47 - 9.52	9.50	11.68 - 11.80	11.74
September	40,000	9.50 - 9.55	9.52	11.73 - 11.85	11.79
October	40,000	9.58 - 9.63	9.61	11.83 - 11.95	11.89
November	40,000	9.88 - 9.93	9.91	12.30 - 12.40	12.35
December	40,000	9.87 - 10.30	10.09	12.55 - 12.71	12.63

Financial Price Swap Contracts. The total fair value of EOG's natural gas financial price swap contracts at December 31, 2008 was a positive $805 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at February 25, 2009. The notional volumes are expressed in MMBtud and prices are expressed in $/MMBtu. The average price of EOG's natural gas financial price swap contracts for 2009 is $9.71 per MMBtu and for 2010 is $9.87 per MMBtu.

Natural Gas Financial Price Swap Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2009		
January (closed)	585,000	$10.76
February (closed)	585,000	10.74
March (closed)	585,000	10.50
April	610,000	9.24
May	610,000	9.16
June	610,000	9.21
July	610,000	9.29
August	610,000	9.34
September	610,000	9.36
October	610,000	9.42
November	610,000	9.66
December	610,000	9.98
2010		
January	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21
July	20,000	9.31
August	20,000	9.38
September	20,000	9.40
October	20,000	9.49
November	20,000	9.80
December	20,000	10.21

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. The total fair value of EOG's natural gas financial basis swap contracts at December 31, 2008 was a negative $25 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at February 25, 2009. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap. The notional volumes are expressed in MMBtud and price differentials expressed in $/MMBtu.

Natural Gas Financial Basis Swap Contracts		
	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2009		
Second Quarter	65,000	$(2.54)
Third Quarter	65,000	(2.60)
Fourth Quarter	65,000	(3.03)
2010		
First Quarter	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

Financing

EOG's debt-to-total capitalization ratio was 17% at December 31, 2008 compared to 14% at December 31, 2007.

During 2008, total debt increased $712 million to $1,897 million. The estimated fair value of EOG's debt at December 31, 2008 and 2007 was $1,933 million and $1,227 million, respectively. The fair value of 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 estimated fair value of debt 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, 2008, a 1% decline in interest rates would result in an $115 million increase in the estimated fair value of the fixed rate obligations. See Note 2 to Consolidated Financial Statements.

During 2008 and 2007, EOG utilized cash provided by operating activities, proceeds from the offering of its 6.125% Senior Notes due 2013 and its 6.875% Senior Notes due 2018 described below, proceeds from the sale of EOG's Appalachian assets, cash provided by borrowings from net commercial paper, other uncommitted credit facilities and a revolving credit facility to fund its capital programs. While EOG maintains a $1.0 billion commercial paper program, the maximum outstanding at any time during 2008 was $704 million, and the amount outstanding at year-end was zero. The maximum amount outstanding under uncommitted credit facilities during 2008 was $130 million with no amounts outstanding at year-end. EOG considers this excess availability, which is backed by the $1.0 billion unsecured Revolving Credit Agreement with domestic and foreign lenders described in Note 2 to Consolidated Financial Statements, to be ample to meet its ongoing operating needs.

On September 30, 2008, EOG completed its public offering of $400 million aggregate principal amount of 6.125% Senior Notes due 2013 and $350 million aggregate principal amount of 6.875% Senior Notes due 2018 (collectively, Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning April 1, 2009. Net proceeds from the offering of approximately $743 million were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

During September 2007, EOG issued $600 million aggregate principal amount of its 5.875% Senior Notes due 2017. 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. In January 2008, EOG repurchased the remaining 5,000 outstanding shares of its Series B for an aggregate purchase price, including a premium, of approximately $5.4 million. The premium of $0.4 million associated with the repurchase was included as a component of preferred stock dividends. As of December 31, 2008, no shares of Series B remain outstanding. See Note 3 to Consolidated Financial Statements.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2008 (in thousands):

Contractual Obligations (1)	Total	2009	2010 - 2011	2012 - 2013	2014 & Beyond
Long-Term Debt	$ 1,897,000	$ 37,000	$ 220,000	$ 400,000	$ 1,240,000
Non-Cancelable Operating Leases	290,725	70,125	72,311	44,388	103,901
Interest Payments on Long-Term Debt	947,659	115,999	231,295	200,495	399,870
Pipeline Transportation Service Commitments (2)	1,984,199	213,516	435,780	417,998	916,905
Drilling Rig Commitments (3)	246,853	179,984	66,869	-	-
Seismic Purchase Obligations	1,000	1,000	-	-	-
Other Purchase Obligations	81,373	60,652	20,721	-	-
Total Contractual Obligations	**$ 5,448,809**	**$ 678,276**	**$ 1,046,976**	**$ 1,062,881**	**$ 2,660,676**

(1) This table does not include the liability for unrecognized tax benefits, EOG's pension or postretirement benefit obligations or liability for dismantlement, abandonment and restoration costs of oil and gas properties (see Notes 5, 6 and 14, respectively, 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, 2008. 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. EOG's expenditures for drilling rig services will exceed such minimum amounts to the extent EOG utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract or if EOG utilizes drilling rigs in addition to the drilling rigs subject to the particular contractual commitment (for example, pursuant to the exercise of an option to utilize additional drilling rigs provided for in the governing contract).

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)(ii) of Regulation S-K) during any of the periods covered by this report, and currently has no intention of participating in any such transaction or arrangement in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2008, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad, the United Kingdom and China. The foreign currency most significant to EOG's operations during 2008 was the Canadian dollar. The fluctuation of the Canadian dollar in 2008 impacted both the revenues and expenses of EOG's Canadian subsidiaries. However, since Canadian commodity 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. Under those provisions, as of December 31, 2008, EOG recorded the fair value of the swap of $26 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 negative change of $7 million for the year ended December 31, 2008. 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 and natural gas liquids prices. However, crude oil and condensate and natural gas liquids comprised a larger portion of EOG's product mix in 2008 than in prior years and is expected to increase further in 2009. Longer term natural gas prices will be determined by the supply of 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 and natural gas liquids in 2009 will impact the amount of cash generated from operating activities, which will in turn impact the level of EOG's 2009 total capital expenditures as well as its production.

Including the impact of EOG's 2009 natural gas hedges, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2009 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 $17 million for net income and $25 million for operating cash flow. EOG's price sensitivity in 2009 for each $1.00 per barrel change in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $14 million for net income and $21 million for operating cash flow. For information regarding EOG's natural gas hedge position as of December 31, 2008, 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 2009, EOG expects to allocate a slightly lower percentage of its domestic exploration and development expenditures to the Fort Worth Basin Barnett Shale area and the Rocky Mountain operating area than in 2008. EOG will also execute a steady drilling program to further develop the British Columbia Horn River Basin. In order to diversify its overall asset portfolio, 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 2009 exploration and development expenditures, excluding acquisitions, are approximately $2,850 million. In addition, budgeted 2009 expenditures for gathering and processing and other assets are approximately $250 million. The total 2009 capital expenditures budget of approximately $3.1 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 2009 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, EOG believes net operating cash flow and available financing alternatives in 2009 will be sufficient to fund its net investing cash requirements for the year. However, EOG has significant flexibility with respect to its financing alternatives and adjustment of its exploration, exploitation, development and acquisition expenditure plans if circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad, the United Kingdom North Sea and China, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Operations. EOG expects to increase overall production in 2009 by 3% over 2008 levels based on average natural gas prices of $5.00 per Mcf at Henry Hub, West Texas Intermediate crude oil prices of $50.00 per barrel and a total budget for exploration and development expenditures of $2,850 million, excluding acquisitions. United States production is expected to increase by 2%, with a planned increase in crude oil and condensate and natural gas liquids production of 10% and 24%, 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 local, state, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by certain of the Canadian provinces in which EOG operates. 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. Any direct and indirect costs of these regulations may adversely affect EOG's business, results of operations and financial condition.

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

Oil and Gas Exploration Costs

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 EOG has 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, 2008 and 2007, EOG had exploratory drilling costs related to projects that have been deferred for more than one year (see Note 16 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, including natural gas gathering and processing facilities, are depreciated on a straight-line basis over the estimated useful life of the asset.

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 No. 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 and projections regarding EOG's future financial position, operations, performance, business strategy, budgets, reserve information, levels of production and costs and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "goal," "may," "will" 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 EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production or 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 reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that these expectations will be achieved or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known and unknown risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's 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 prices for natural gas, crude oil and related commodities;
- changes in demand for natural gas, crude oil and related commodities, including ammonia and methanol;
- the extent to which EOG is successful in its efforts to discover, develop, market and produce reserves and to acquire natural gas and crude oil properties;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling and advanced completion technologies;
- the extent to which EOG is successful in its efforts to economically develop its acreage in the Barnett Shale, the Bakken Formation, its Horn River Basin and Haynesville plays and its other exploration and development areas;
- EOG's ability to achieve anticipated production levels from existing and future natural gas and crude oil development projects, given the risks and uncertainties inherent in drilling, completing and operating natural gas and crude oil wells and the potential for interruptions of production, whether involuntary or intentional as a result of market or other conditions;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights of way;
- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- EOG's ability to obtain access to surface locations for drilling and production facilities;
- the extent to which EOG's third-party-operated natural gas and crude oil properties are operated successfully and economically;
- EOG's ability to effectively integrate acquired natural gas and crude oil properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;

- weather, including its impact on natural gas and crude oil demand, and weather-related delays in drilling and in the installation and operation of gathering and production facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and impact of liquefied natural gas imports;
- the use of competing energy sources and the development of alternative energy sources;
- political developments around the world, including in the areas in which EOG operates;
- changes in government policies, legislation and regulations, including environmental regulations;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors," on pages 13 through 19 of this Annual Report on Form 10-K and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and you should not place any undue reliance on any of EOG's forward-looking statements. 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, 2008. 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, 2008 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, or 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, 2008. 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, 2008. 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, 2008 that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

ITEM 9B. ***Other Information***

None.

PART III

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

The information required by this Item is incorporated by reference from (i) EOG's Definitive Proxy Statement with respect to its 2009 Annual Meeting of Stockholders to be filed not later than April 30, 2009 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. EOG has also adopted a Code of Ethics for Senior Financial Officers (Code of Ethics) that, along with EOG's Code of Conduct, applies to EOG's principal executive officer, principal financial and accounting officer and controllers.

You can access the Code of Conduct and Code of Ethics 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 and Code of Ethics by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose amendments to the Code of Conduct and Code of Ethics, and waivers with respect to the Code of Conduct and Code of Ethics 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 EOG's Definitive Proxy Statement with respect to its 2009 Annual Meeting of Stockholders to be filed not later than April 30, 2009. 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 EOG's Definitive Proxy Statement with respect to its 2009 Annual Meeting of Shareholders to be filed not later than April 30, 2009.

Equity Compensation Plan Information

Stock Plans Approved by EOG Stockholders. EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. The 2008 Plan provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards, up to an aggregate maximum of 6.0 million shares of common stock, plus shares underlying forfeited or cancelled grants under EOG's prior stock plans referenced below. Under the 2008 Plan, grants may be made to employees and non-employee members of EOG's Board of Directors (Board). The 2008 Plan, the 1992 Stock Plan, the 1993 Nonemployee Directors Stock Option Plan and the Employee Stock Purchase Plan have been approved by EOG's stockholders. Plans that have not been approved by EOG's stockholders are described below.

The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by EOG's stockholders and those plans not approved by EOG's stockholders as of December 31, 2008.

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 EOG Stockholders	9,009,610	$64.85	4,665,770 (1) (2)
Equity Compensation Plans Not Approved by EOG Stockholders	1,914,150	$22.26	21,824 (3)
Total	**10,923,760**	**$57.39**	**4,687,594**

(1) Of these securities, 110,491 shares remain available for purchase under the Employee Stock Purchase Plan.
(2) Of these securities, 1,965,686 could be issued as restricted stock or restricted stock units under the 2008 Plan.
(3) Represents 21,824 shares that remain available for issuance under the Deferral Plan (as described below). See the related discussion below regarding the amendment and continuation of the 1996 Deferral Plan.

Stock Plans Not Approved by EOG Stockholders. The Board 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 1994 Stock Plan, employees have been granted stock options (rights to purchase shares of EOG common stock at a price not less than the market price of the stock on the date of grant). These 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 1994 Stock Plan have not exceeded a maximum term of 10 years. Employees have also been granted under the 1994 Stock Plan 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. Restricted shares, upon vesting, are released to the employee. Each restricted stock unit, upon vesting, is converted into one share of EOG common stock and released to the employee. Upon the effective date of the 2008 Plan, no further grants were made under the 1994 Stock Plan.

In December 2008, the Board approved the amendment and continuation of the 1996 Deferral Plan as the "EOG Resources, Inc. 409A Deferred Compensation Plan" (Deferral Plan). Under the Deferral Plan, payment of up to 50% of base salary, 100% of annual cash bonus, directors fees and 401(k) refunds resulting from excess deferrals in the EOG Savings Plan 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 Deferral Plan. As of December 31, 2008, 98,176 phantom shares had been issued.

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

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2009 Annual Meeting of Stockholders to be filed not later than April 30, 2009.

ITEM 14. ***Principal Accounting Fees and Services***

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2009 Annual Meeting of Stockholders to be filed not later than April 30, 2009.

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-6 for a listing of the exhibits.

EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

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

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc., 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, 2008. 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, 2008.

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
Chairman of the Board and
Chief Executive Officer

TIMOTHY K. DRIGGERS
Vice President and Chief
Financial Officer

Houston, Texas
February 25, 2009

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, 2008 and 2007, 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, 2008. 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, 2008, 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, and 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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

DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2009

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

Year Ended December 31	2008	2007	2006
Net Operating Revenues			
Natural Gas	$ 4,452,058	$ 3,032,805	$ 2,792,920
Crude Oil, Condensate and Natural Gas Liquids	1,769,926	987,523	761,580
Gains on Mark-to-Market Commodity Derivative Contracts	597,911	93,108	334,260
Gathering, Processing and Marketing	164,535	73,539	29,733
Other, Net	142,713	52,328	10,148
Total	7,127,143	4,239,303	3,928,641
Operating Expenses			
Lease and Well	559,185	452,044	355,610
Transportation Costs	274,090	152,236	100,004
Gathering and Processing Costs	40,550	27,775	17,285
Exploration Costs	193,886	150,445	155,008
Dry Hole Costs	55,167	115,382	79,567
Impairments	192,859	147,517	108,258
Marketing Costs	152,842	66,680	26,423
Depreciation, Depletion and Amortization	1,326,875	1,065,545	817,089
General and Administrative	243,708	205,210	164,981
Taxes Other Than Income	320,796	208,073	200,863
Total	3,359,958	2,590,907	2,025,088
Operating Income	3,767,185	1,648,396	1,903,553
Other Income, Net	31,012	29,250	52,246
Income Before Interest Expense and Income Taxes	3,798,197	1,677,646	1,955,799
Interest Expense			
Incurred	94,286	76,102	63,058
Capitalized	(42,628)	(29,324)	(19,900)
Net Interest Expense	51,658	46,778	43,158
Income Before Income Taxes	3,746,539	1,630,868	1,912,641
Income Tax Provision	1,309,620	540,950	612,756
Net Income	2,436,919	1,089,918	1,299,885
Preferred Stock Dividends	443	6,663	10,995
Net Income Available to Common Stockholders	**$ 2,436,476**	**$ 1,083,255**	**$ 1,288,890**
Net Income Per Share Available to Common Stockholders			
Basic	$ 9.88	$ 4.45	$ 5.33
Diluted	$ 9.72	$ 4.37	$ 5.24
Average Number of Common Shares			
Basic	246,662	243,469	241,782
Diluted	250,542	247,637	246,100
Comprehensive Income			
Net Income	$ 2,436,919	$ 1,089,918	$ 1,299,885
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	(431,940)	282,619	883
Foreign Currency Swap Transaction	(9,637)	10,789	(219)
Income Tax Related to Foreign Currency Swap Transaction	2,442	(3,086)	(605)
Defined Benefit Pension and Post-Retirement Plans	608	(595)	-
Income Tax Related to Defined Benefit Pension and Post-Retirement Plans	(388)	271	-
Comprehensive Income	**$ 1,998,004**	**$ 1,379,916**	**$ 1,299,944**

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

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

At December 31	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 331,311	$ 54,231
Accounts Receivable, Net	722,695	835,670
Inventories	187,970	102,322
Assets from Price Risk Management Activities	779,483	100,912
Income Taxes Receivable	27,053	110,370
Deferred Income Taxes	-	33,533
Other	59,939	55,001
Total	2,108,451	1,292,039
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	20,803,629	16,981,836
Other Property, Plant and Equipment	1,057,888	581,402
Total Property, Plant and Equipment	21,861,517	17,563,238
Less: Accumulated Depreciation, Depletion and Amortization	(8,204,215)	(7,133,984)
Total Property, Plant and Equipment, Net	13,657,302	10,429,254
Long-Term Assets Held for Sale	-	254,376
Other Assets	185,473	113,238
Total Assets	**$ 15,951,226**	**$ 12,088,907**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 1,122,209	$ 1,152,140
Accrued Taxes Payable	86,265	104,647
Dividends Payable	33,461	22,045
Liabilities from Price Risk Management Activities	4,429	3,404
Deferred Income Taxes	368,231	108,980
Current Portion of Long-Term Debt	37,000	-
Other	113,321	82,954
Total	1,764,916	1,474,170
Long-Term Debt	1,860,000	1,185,000
Other Liabilities	498,291	368,336
Deferred Income Taxes	2,813,522	2,071,307
Stockholders' Equity		
Preferred Stock, $0.01 Par, Zero Shares and 10,000,000 Shares Authorized at December 31, 2008 and 2007, respectively:		
Series B, Cumulative, $1,000 Liquidation Preference Per Share, Zero Shares and 5,000 Shares Outstanding at December 31, 2008, and 2007, respectively	-	4,977
Common Stock, $0.01 Par, 640,000,000 Shares Authorized: 249,758,577 Shares and 249,460,000 Shares Issued at December 31, 2008 and 2007, respectively	202,498	202,495
Additional Paid in Capital	323,805	221,102
Accumulated Other Comprehensive Income	27,787	466,702
Retained Earnings	8,466,143	6,156,721
Common Stock Held in Treasury, 126,911 Shares and 2,935,313 Shares at December 31, 2008 and 2007, respectively	(5,736)	(61,903)
Total Stockholders' Equity	9,014,497	6,990,094
Total Liabilities and Stockholders' Equity	**$ 15,951,226**	**$ 12,088,907**

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

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, 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
Net Income	-	-	-	-	-	2,436,919	-	2,436,919
Redemption of Preferred Stock	(5,000)	-	-	-	-	-	-	(5,000)
Amortization of Preferred Stock Discount	23	-	-	-	-	(23)	-	-
Preferred Stock Dividends Declared	-	-	-	-	-	(420)	-	(420)
Common Stock Dividends Declared, $0.51 Per Share	-	-	-	-	-	(127,054)	-	(127,054)
Translation Adjustment	-	-	-	-	(431,940)	-	-	(431,940)
Foreign Currency Swap Transaction, Net of Tax	-	-	-	-	(7,195)	-	-	(7,195)
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	-	-	220	-	-	220
Treasury Stock Issued Under Stock Plans	-	-	7,260	-	-	-	47,649	54,909
Tax Benefits from Stock-Based Compensation	-	-	6,446	-	-	-	-	6,446
Restricted Stock and Units	-	3	(8,515)	-	-	-	8,512	-
Expense on Stock-Based Compensation	-	-	97,493	-	-	-	-	97,493
Treasury Stock Issued as Compensation	-	-	19	-	-	-	6	25
Balance at December 31, 2008	$ -	$202,498	$323,805	$ -	$ 27,787	$8,466,143	$ (5,736)	$9,014,497

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	**2008**	**2007**	**2006**
Cash Flows From Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 2,436,919	$ 1,089,918	$ 1,299,885
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	1,326,875	1,065,545	817,089
Impairments	192,859	147,517	108,258
Stock-Based Compensation Expenses	97,493	67,253	49,875
Deferred Income Taxes	1,133,630	426,827	385,842
Other, Net	(138,392)	(44,138)	(18,404)
Dry Hole Costs	55,167	115,382	79,567
Mark-to-Market Commodity Derivative Contracts			
Total Gains	(597,911)	(93,108)	(334,260)
Realized (Losses) Gains	(136,625)	127,969	215,063
Other, Net	13,229	24,268	20,670
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	95,165	(85,024)	9,905
Inventories	(92,049)	9,638	(50,370)
Accounts Payable	30,253	228,354	222,012
Accrued Taxes Payable	66,021	(40,002)	(106,324)
Other Assets	(10,715)	(8,416)	13,060
Other Liabilities	9,061	12,614	7,989
Changes in Components of Working Capital Associated with Investing and Financing Activities	152,269	(143,594)	(123,838)
Net Cash Provided by Operating Activities	4,633,249	2,901,003	2,596,019
Investing Cash Flows			
Additions to Oil and Gas Properties	(4,718,860)	(3,401,986)	(2,750,262)
Additions to Other Property, Plant and Equipment	(476,611)	(277,076)	(99,861)
Proceeds from Sales of Assets	383,559	83,295	20,041
Changes in Components of Working Capital Associated with Investing Activities	(152,374)	143,668	123,890
Other, Net	(2,232)	(3,675)	(4,181)
Net Cash Used in Investing Activities	(4,966,518)	(3,455,774)	(2,710,373)
Financing Cash Flows			
Long-Term Debt Borrowings	750,000	610,000	65,000
Long-Term Debt Repayments	(38,000)	(158,442)	(316,625)
Dividends Paid	(115,204)	(84,020)	(60,443)
Redemption of Preferred Stock	(5,395)	(51,197)	(50,199)
Excess Tax Benefits from Stock-Based Compensation	6,446	27,339	28,188
Treasury Stock Purchased	(17,834)	(7,638)	(17,466)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	72,572	55,320	36,033
Debt Issuance Costs	(7,585)	(5,206)	(615)
Other, Net	105	(71)	(221)
Net Cash Provided by (Used in) Financing Activities	645,105	386,085	(316,348)
Effect of Exchange Rate Changes on Cash	(34,756)	4,662	5,146
Increase (Decrease) in Cash and Cash Equivalents	277,080	(164,024)	(425,556)
Cash and Cash Equivalents at Beginning of Year	54,231	218,255	643,811
Cash and Cash Equivalents at End of Year	**$ 331,311**	**$ 54,231**	**$ 218,255**

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

1. Summary of Significant Accounting Policies

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

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of 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 16). 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, including natural gas gathering and processing facilities, are depreciated on a straight-line basis over the estimated useful life of the asset.

Assets are grouped in accordance with 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, as appropriate, any reductions in value.

Arrangements for natural gas, crude oil and 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.

Gathering, processing and marketing revenues represent sales of third-party natural gas and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. EOG's gathering, processing and marketing revenues were previously presented net of related gas purchase and transportation costs in Other, Net revenues. In addition, certain other expenses previously included in Lease and Well have been reclassified to Gathering and Processing Costs. The effect of these reclassifications on the 2007 and 2006 presentation in the Consolidated Statements of Income and Comprehensive Income was to increase total net operating revenues and total operating expenses by $48.5 million and $16.1 million in 2007 and 2006, respectively. These changes did not impact previously reported operating income, net income or cash flows.

Other Property, Plant and Equipment. Other property, plant and equipment consist of natural gas gathering and processing facilities, 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 (SFAS No. 133). 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, 2008, 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 fair value of outstanding financial instruments are recognized as gains or losses in the period of change. The gains or losses are recorded in Gains (Losses) on Mark-to-Market Commodity Derivative Contracts. The related cash flow impact is reflected as cash flows from operating activities (see Note 11). EOG entered into a foreign currency swap transaction in March 2007 (see Note 2).

As of January 1, 2008, EOG adopted Financial Accounting Standards Board (FASB) Staff Position (FSP) FASB Interpretation (FIN) No. 39-1, "Amendment of FASB Interpretation No. 39" (FSP FIN No. 39-1), which effectively amends FIN No. 39, "Offsetting of Amounts Related to Certain Contracts." FSP FIN No. 39-1 permits the netting of fair values of derivative assets and liabilities for financial reporting purposes, if such assets and liabilities are with the same counterparty and subject to a master netting arrangement. EOG has elected to employ net presentation of derivative assets and liabilities when FSP FIN No. 39-1 conditions are met. FSP FIN No. 39-1 also requires that when derivative assets and liabilities are presented net, the fair value of the right to reclaim collateral assets (receivable) or the obligation to return cash collateral (payable) is also offset against the net fair value of the corresponding derivative. Netting collateral assets and liabilities against corresponding derivative balances represents a change in accounting policy. At December 31, 2008 and 2007, there were no collateral assets or liabilities associated with derivative assets and liabilities.

Income Taxes. EOG accounts for income taxes under the provisions of SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109). 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. In accordance with the provisions of SFAS No. 123 (R), "Share Based Payment" (SFAS No. 123 (R)), EOG measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In connection with the adoption of SFAS No. 123 (R), Unearned Compensation previously included separately in Stockholders' Equity was written off against Additional Paid in Capital at the date of adoption.

EOG has adopted the alternative transition method prescribed in FSP FAS 123R-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards" (FSP FAS 123R-2), 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 No. 123 (R).

Recently Issued Accounting Standards and Developments. In December 2008, the United States Securities and Exchange Commission (SEC) released a final rule, "Modernization of Oil and Gas Reporting," which amends the oil and gas reporting requirements. The key revisions to the reporting requirements include: using a 12-month average price to determine reserves; including nontraditional resources in reserves if they are intended to be upgraded to synthetic oil and gas; ability to use new technologies to determine and estimate reserves; and permitting the disclosure of probable and possible reserves. In addition, the final rule includes the requirements to report the independence and qualifications of the reserve preparer or auditor; file a report as an exhibit when a third party is relied upon to prepare reserve estimates or conduct reserve audits; and to disclose the development of any proved undeveloped reserves (PUDs), including the total quantity of PUDs at year-end, material changes to PUDs during the year, investments and progress toward the development of PUDs and an explanation of the reasons why material concentrations of PUDs have remained undeveloped for five years or more after disclosure as PUDs. The accounting changes resulting from changes in definitions and pricing assumptions should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, which is to be applied prospectively. The final rule is effective for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. EOG is assessing the impact that this final rule will have on its financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 does not change the scope or accounting of SFAS No. 133 as amended, but expands disclosure requirements about an entity's derivative instruments and hedging activities. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is permitted and comparative disclosures for earlier periods are encouraged. The adoption of SFAS No. 161 will result in additional disclosures related to derivative instruments and hedging activities.

During February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FASB Statement No. 115" (SFAS No. 159). 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 was effective as of the beginning of the first fiscal year beginning after November 15, 2007. EOG elected not to adopt the fair value option provision allowed under SFAS No. 159.

In September 2006, the 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)." 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). SFAS No. 157 provides a definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. 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 FSP 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. EOG partially adopted SFAS No. 157 effective January 1, 2008. See Note 12.

During July 2006, the FASB issued FIN No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" (FIN No. 48). FIN No. 48 addresses the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109. 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 was 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. See Note 5.

2. Long-Term Debt

Long-Term Debt at December 31, 2008 and 2007 consisted of the following (in thousands):

	2008	2007
6.125% Senior Notes due 2013	$ 400,000	$ -
5.875% Notes due 2017	600,000	600,000
6.875% Senior Notes due 2018	350,000	-
6.65% Notes due 2028	140,000	140,000
Subsidiary Revolving Credit Facility due 2009	37,000	75,000
7.00% Subsidiary Debt due 2011	220,000	220,000
4.75% Subsidiary Debt due 2014	150,000	150,000
	1,897,000	1,185,000
Less: Current Portion of Long-Term Debt	37,000	-
Total	**$ 1,860,000**	**$ 1,185,000**

At December 31, 2008, the aggregate annual maturities of long-term debt were $37 million in 2009, zero in 2010, $220 million in 2011, zero in 2012 and $400 million in 2013.

During 2008 and 2007, EOG utilized commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper or uncommitted credit facilities at December 31, 2008. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for 2008 were 3.13% and 3.36%, respectively.

On September 30, 2008, EOG completed its public offering of $400 million aggregate principal amount of 6.125% Senior Notes due 2013 and $350 million aggregate principal amount of 6.875% Senior Notes due 2018 (Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning April 1, 2009. Net proceeds from the offering of approximately $743 million were used for general corporate purposes, including repayment of outstanding commercial paper and borrowings under other uncommitted credit facilities.

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, as amended in June 2006 (Agreement), with domestic and foreign lenders and JPMorgan 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, 2008, 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, 2008, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 0.63% and 3.25%, respectively.

In May 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. In the second quarter of 2008, EOG repaid $38 million of the $75 million outstanding and at December 31, 2008, $37 million remained outstanding under the Credit Agreement. The applicable Eurodollar rate at December 31, 2008 was 2.85%. The weighted average Eurodollar rate for the amounts outstanding during the year ended December 31, 2008 was 3.51%.

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 6.125% Senior Notes due 2013, the 2017 Notes, the 6.875% Senior Notes due 2018 and the 6.65% Notes due 2028 were issued through public offerings and have effective interest rates of 6.276%, 5.971%, 7.042% and 6.65%, respectively. The 7.00% 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 201.3 million Canadian dollars with a 5.275% interest rate.

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 Canadian notes. 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. Under those provisions, as of December 31, 2008 and 2007, EOG recorded the fair value of the swap of $26 million and $58 million, respectively, 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 is included in Accumulated Other Comprehensive Income in the Stockholders' Equity section of the Consolidated Balance Sheets.

Fair Value of Long-Term Debt. At December 31, 2008 and 2007, EOG had $1,897 million and $1,185 million, respectively, of long-term debt, which had estimated fair values of approximately $1,933 million and $1,227 million, respectively. The fair value of long-term debt is the value EOG estimates it 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 estimated fair value of long-term debt was 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 shares of its common stock from time to time in the open market. 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 that superseded all previous authorizations. At December 31, 2008, 6,386,200 shares remained available for purchases under this authorization. In addition, shares of EOG's common stock are from time to time withheld by, or returned to, EOG in satisfaction of tax withholding obligations arising upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options. Such shares withheld or returned are not included in the Board authorization discussed above. Shares purchased, withheld and returned are 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.

The Board increased the quarterly cash dividend on EOG's common stock from $0.04 per share to $0.06 per share on February 1, 2006 effective beginning with the dividend paid on April 28, 2006, to $0.09 per share on January 31, 2007 effective beginning with the dividend paid on April 30, 2007, to $0.12 per share on February 7, 2008 effective beginning with the dividend paid on April 30, 2008 and to $0.135 per share on July 29, 2008 effective beginning with the dividend paid on October 31, 2008.

On February 4, 2009, EOG's Board increased the quarterly cash dividend on the common stock from the previous $0.135 per share to $0.145 per share effective beginning with the dividend to be paid on April 30, 2009.

The following summarizes EOG's common stock activity for each of the years ended December 31, 2006, 2007 and 2008 (in thousands):

	Common Shares		
	Issued	**Treasury**	**Outstanding**
Balance at December 31, 2005	249,460	(7,386)	242,074
Treasury Stock Purchased [(1)]	-	(265)	(265)
Treasury Stock Issued Under Employee Stock Purchase Plan	-	92	92
Treasury Stock Issued Under Other Equity Compensation Plans	-	1,834	1,834
Balance at December 31, 2006	249,460	(5,725)	243,735
Treasury Stock Purchased [(1)]	-	(126)	(126)
Treasury Stock Issued Under Employee Stock Purchase Plan	-	102	102
Treasury Stock Issued Under Other Equity Compensation Plans	-	2,814	2,814
Balance at December 31, 2007	249,460	(2,935)	246,525
Common Stock Issued Under Equity Compensation Plans	299	-	299
Treasury Stock Purchased [(1)]	-	(195)	(195)
Treasury Stock Issued Under Employee Stock Purchase Plan	-	103	103
Treasury Stock Issued Under Other Equity Compensation Plans	-	2,900	2,900
Balance at December 31, 2008	249,759	(127)	249,632

(1) Represents shares that were withheld by, or returned to, EOG in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options.

Common Stock Rights Agreement. In February 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 in March 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. The holders 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 in March 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 one 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, 2008, 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 Senior Preferred Stock, Series B, with a $1,000 liquidation preference per share (Series B). Dividends were 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 purchased 46,740 shares of the Series B pursuant to the tender offer for an aggregate purchase price, including premium, fees and dividends, of approximately $51 million. EOG included the $4 million of premium and fees associated with the purchase of the Series B shares as a component of preferred stock dividends for fiscal year 2006.

In 2007, EOG purchased 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 purchase. EOG included the $3 million of premium and fees associated with the purchase as a component of preferred stock dividends for fiscal year 2007.

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

In March 2008, EOG filed a certificate of elimination with respect to the Series B with the Delaware Secretary of State, eliminating all matters with respect to the Series B from EOG's restated certificate of incorporation and effectively eliminating the Series B as an authorized series of EOG's preferred stock.

4. Other Income, Net

Other income, net for 2008 included interest income ($9 million), equity income from investments in the Caribbean Nitrogen Company Limited (CNCL) and Nitrogen (2000) Unlimited (N2000) ammonia plants ($19 million), net foreign currency transaction losses ($5 million) and settlements received related to the Enron Corp. bankruptcy ($3 million). Other income, net for 2007 included interest income ($10 million), equity income from investments in CNCL and 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, 2008 and 2007 were as follows (in thousands):

	2008	2007
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	$ 276,438	$ -
Deferred Compensation Plans	(8,226)	-
Timing Differences Associated With Different Year-ends in Foreign Jurisdictions	98,736	108,207
Other	1,283	773
Total Net Current Deferred Income Tax Liabilities	**$ 368,231**	**$ 108,980**
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 3,094,143	$ 2,267,948
Non-Producing Leasehold Costs	(50,841)	(67,824)
Seismic Costs Capitalized for Tax	(47,325)	(46,546)
Equity Awards	(52,300)	(32,130)
Capitalized Interest	62,488	35,424
Alternative Minimum Tax Credit Carryforward	(143,142)	(35,537)
Other	(49,501)	(50,028)
Total Net Noncurrent Deferred Income Tax Liabilities	**$ 2,813,522**	**$ 2,071,307**
Total Net Deferred Income Tax Liabilities	**$ 3,181,753**	**$ 2,146,754**

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

	2008	2007	2006
United States	$ 3,138,175	$ 1,191,093	$ 1,343,669
Foreign	608,364	439,775	568,972
Total	**$ 3,746,539**	**$ 1,630,868**	**$ 1,912,641**

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

	2008	2007	2006
Current:			
Federal	$ 50,776	$ (7,284)	$ 78,910
State	5,674	(3,999)	1,050
Foreign	119,540	125,406	146,954
Total	175,990	114,123	226,914
Deferred:			
Federal	1,010,535	416,925	377,543
State	56,540	26,506	11,475
Foreign	66,555	(16,604)	(3,176)
Total	1,133,630	426,827	385,842
Income Tax Provision	**$ 1,309,620**	**$ 540,950**	**$ 612,756**

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

	2008	2007	2006
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	1.08	0.90	0.15
Income Tax Provision Related to Foreign Operations	(0.72)	(0.67)	(0.10)
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
Domestic Production Activities Deduction	0.01	0.11	(0.06)
Other	(0.41)	(0.07)	(0.42)
Effective Income Tax Rate	34.96%	33.17%	32.04%

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. During 2008, the balance of unrecognized tax benefits increased to $13 million, all of which, if recognized, would affect the effective tax rate. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. There are no amounts of interest or penalties recognized in the Consolidated Statements of Income and Comprehensive Income or in the Consolidated Balance Sheets. EOG does not anticipate that the amount of the unrecognized tax benefits will significantly change during the next twelve months. 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 2005, 2004, 2006 and 1998, respectively.

EOG's foreign subsidiaries' undistributed earnings of approximately $2.6 billion at December 31, 2008 are considered to be indefinitely invested outside the United States and, accordingly, no United States federal 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.

In 2008, EOG generated a regular tax net operating loss of $184 million, which is expected to be carried forward and applied against regular taxable income in future periods. SFAS No. 123 (R), which relates to accounting for share-based compensation, provides that when settlement of a share award contributes to a net operating loss carryforward, neither the associated excess tax benefit nor the credit to additional paid in capital (APIC) should be recorded until the share award deduction reduces income taxes payable. Upon utilization of the loss in future periods, a benefit of $65 million will be reflected in APIC. In 2008, EOG paid alternative minimum tax (AMT) of $80 million. The AMT paid in 2008, along with AMT of $42 million and $21 million paid in 2007 and 2006, respectively, 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, 2008, 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 did 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 2008, approximately $0.3 million from such plans 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 $20 million, $16 million and $14 million for 2008, 2007 and 2006, 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, $2.7 million and $2.1 million for 2008, 2007 and 2006, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and prepaid/(accrued) benefit cost totaled $6.2 million, $6.2 million and $0.3 million, respectively, at December 31, 2008 and $7.3 million, $7.3 million and ($0.03) million, respectively, at December 31, 2007. 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 7.90%, 8.05%, 5.80% and 1.46%, respectively, at December 31, 2008; 6.85%, 7.47%, 5.15% and 1.90%, respectively, at December 31, 2007; and 5.98%, 7.10%, 4.20% and 2.40%, respectively, at December 31, 2006. Weighted average discount rate, rate of compensation increase and rate of pension increase assumptions used to determine benefit obligations for the pension plans were 7.59%, 5.02% and 1.99%, respectively, for the year ended December 31, 2008 and 6.43%, 4.52% and 2.32%, respectively, for the year ended December 31, 2007. The weighted average asset allocation at December 31, 2008 consisted of equities (48%), debt and fixed income securities (44%) and other assets (8%). The weighted average asset allocation at December 31, 2007 consisted of equities (55%), debt and fixed income securities (39%) and other assets (6%).

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 for each of the years 2008, 2007 and 2006.

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 each totaled $4.4 million at December 31, 2008 and $4.0 million and $3.9 million, respectively, at December 31, 2007. Weighted average discount rate assumptions used to determine benefit obligations for the postretirement plans at December 31, 2008 and 2007 were 6.25% and 6.29%, respectively. Weighted average discount rate assumptions used to determine net periodic benefit cost for the years ended December 31, 2008, 2007 and 2006 were 6.33%, 5.96% and 5.68%, respectively. Net periodic benefit cost recognized for the postretirement benefit plans totaled $0.8 million, $0.7 million and $0.7 million for the years ended December 31, 2008, 2007 and 2006.

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
2009	$ 225	$ 165
2010	224	195
2011	273	235
2012	240	268
2013	261	324
2014 - 2018	2,206	2,501

Postretirement health care trend rates had minimal effect on the amounts reported for the postretirement health care plans for both 2008 and 2007. Most future increases or decreases in healthcare costs would be borne by the employee.

Stock-Based Compensation

During 2008, 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 No. 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 restricted stock 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 includes 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 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, 2008, 2007 and 2006 was as follows (in millions):

	2008	2007	2006
Lease and Well	$ 20	$ 14	$ 10
Exploration Costs	18	13	11
General and Administrative	59	40	29
Total	$ 97	$ 67	$ 50

EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. The 2008 Plan provides for grants of stock options, SARs, restricted stock, restricted stock units and other stock-based awards, up to an aggregate maximum of 6.0 million shares of common stock, plus shares underlying forfeited or cancelled grants under the prior stock plans. Under the 2008 Plan, grants may be made to employees and non-employee members of EOG's Board. At December 31, 2008, approximately 4.6 million common shares remained available for grant under the 2008 Plan. Effective with the adoption of the 2008 Plan, EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares.

During 2008, 2007 and 2006, EOG issued treasury shares in connection with stock option exercises, restricted stock grants, restricted stock 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 $6 million, $29 million and $31 million for 2008, 2007 and 2006, respectively, related to the exercise of stock options/SARs and the release of restricted stock and restricted stock units.

Stock Options and Stock Appreciation Rights and Employee Stock Purchase Plan. Participants in EOG's stock plans (including the 2008 Plan) have been or may be granted options to purchase shares of common stock of EOG. In addition, participants in EOG's stock plans (including the 2008 Plan) 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 SARs granted. Stock options and SARs are granted at a price not less than the market price of the common stock on the date of grant. Stock options and SARs granted 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 have not exceeded a maximum term of 10 years. EOG's ESPP 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 employee's pay (subject to certain ESPP limits) during each of the two six-month offering periods each year.

The fair value of all stock option grants made prior to August 2004 and all ESPP grants is 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 of EOG's common stock 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 option, SAR and ESPP grants totaled $38.9 million, $36.7 million and $34.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2008, 2007 and 2006 were as follows:

	Stock Options/SARs			**ESPP**		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Weighted Average Fair Value of Grants	$32.19	$24.23	$22.56	$29.68	$16.11	$20.32
Expected Volatility	38.55%	30.68%	34.22%	37.58%	29.76%	41.09%
Risk-Free Interest Rate	2.53%	4.48%	4.96%	2.64%	5.01%	4.89%
Dividend Yield	0.60%	0.30%	0.30%	0.50%	0.30%	0.30%
Expected Life	5.3 yrs	5.2 yrs	5.1 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 common 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 option, SAR and ESPP grants.

The following table sets forth the stock option and SAR transactions for the years ended December 31, 2008, 2007 and 2006 (stock options and SARs in thousands):

	2008		2007		2006	
	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	9,373	$41.04	10,150	$35.29	9,698	$28.26
Granted	1,231	90.57	1,210	73.46	2,038	62.25
Exercised (1)	(2,628)	28.19	(1,820)	29.12	(1,368)	23.80
Forfeited	(174)	69.22	(167)	56.39	(218)	42.03
Outstanding at December 31	7,802	52.56	9,373	41.04	10,150	35.29
Stock Options/SARs Exercisable at December 31	4,711	37.23	5,617	27.21	5,325	20.91
Available for Future Grant	4,555		1,140		3,233	

(1) The total intrinsic value of stock options/SARs exercised during the years 2008, 2007 and 2006 was $217.9 million, $86.4 million and $65.0 million, respectively. The intrinsic value is based upon the difference between the market price of EOG common stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2008, there are 7,568,731 stock options/SARs vested or expected to vest with a weighted average grant price of $51.81, an intrinsic value of $146 million and a weighted average remaining contractual life of 4.5 years.

As of December 31, 2008, approximately 110,500 common shares remained available for issuance under the ESPP. The following table summarizes ESPP activities for the years ended December 31, 2008, 2007 and 2006 (in thousands, except number of participants):

	2008	2007	2006
Approximate Number of Participants	1,075	860	730
Shares Purchased	103	102	92
Aggregate Purchase Price	$ 6,724	$ 5,840	$ 5,110

At December 31, 2008, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $76.1 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.5 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2008 (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	607	2	$15.69		607	2	$15.69	
17.00 to 19.99	1,475	4	18.36		1,475	4	18.36	
20.00 to 48.99	738	4	23.35		733	4	23.25	
49.00 to 69.99	2,649	4	61.95		1,542	4	62.03	
70.00 to 136.99	2,333	6	82.34		354	6	73.83	
	7,802	5	52.56	$146,303	4,711	4	37.23	$140,838

(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 Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. The restricted stock and restricted stock units generally vest five years after the date of grant, except for certain bonus grants, and as defined in individual grant agreements. Upon vesting of restricted stock, common shares are released to the employee. Restricted stock units are converted into common shares upon vesting and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $58.6 million, $30.6 million and $15.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2008, 2007 and 2006 (shares and units in thousands):

	2008		2007		2006	
	Number of Shares and Units	**Weighted Average Grant Date Fair Value**	**Number of Shares and Units**	**Weighted Average Grant Date Fair Value**	**Number of Shares and Units**	**Weighted Average Grant Date Fair Value**
Outstanding at January 1	3,000	$50.61	2,301	$36.13	2,544	$26.04
Granted	795	106.67	1,141	71.28	542	64.29
Released[1]	(623)	22.77	(346)	21.20	(702)	20.74
Forfeited	(124)	67.42	(96)	54.58	(83)	41.50
Outstanding at December 31[2]	3,048	70.24	3,000	50.61	2,301	36.13

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2008, 2007 and 2006 was $55.7 million, $23.8 million and $50.3 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.

(2) The aggregate intrinsic value of restricted stock and restricted stock units outstanding at December 31, 2008 and 2007 was approximately $203.0 million and $267.7 million, respectively.

At December 31, 2008, unrecognized compensation expense related to restricted stock and restricted stock units totaled $122.3 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.8 years.

7. Commitments and Contingencies

Letters of Credit. At December 31, 2008, EOG had standby letters of credit and guarantees outstanding totaling approximately $568 million of which $445 million represents guarantees of subsidiary indebtedness (see Note 2) and $123 million primarily represents guarantees of payment obligations on behalf of subsidiaries. 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 and $138 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 25, 2009, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2008, 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, 2008, are as follows (in thousands):

	Total Minimum Commitments
2009	$ 525,277
2010 - 2011	595,681
2012 - 2013	462,386
2014 and beyond	1,020,806
	$ 2,604,150

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 $70 million, $60 million and $46 million for 2008, 2007 and 2006, 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, 2008, 2007 and 2006 (in thousands, except per share data):

	2008	2007	2006
Numerator for Basic and Diluted Earnings per Share -			
Net Income	$ 2,436,919	$ 1,089,918	$ 1,299,885
Less: Preferred Stock Dividends	443	6,663	10,995
Net Income Available to Common Stockholders	$ 2,436,476	$ 1,083,255	$ 1,288,890
Denominator for Basic Earnings per Share -			
Weighted Average Shares	246,662	243,469	241,782
Potential Dilutive Common Shares -			
Stock Options/SARs	2,629	2,915	3,261
Restricted Stock and Restricted Stock Units	1,251	1,253	1,057
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	250,542	247,637	246,100
Net Income Per Share Available to Common Stockholders			
Basic	$ 9.88	$ 4.45	$ 5.33
Diluted	$ 9.72	$ 4.37	$ 5.24

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. The excluded stock options and SARs totaled 0.1 million, 2.4 million and 0.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

9. Supplemental Cash Flow Information

Cash paid for interest and income taxes was as follows for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	2008	2007	2006
Interest	$ 48,029	$ 38,616	$ 41,174
Income taxes	$ 94,598	$ 144,234	$ 301,214

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 of the Board 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, the United Kingdom North Sea and China. For segment reporting purposes, the chief operating decision maker considers the major United States producing areas to be one operating segment.

Financial information by reportable segment is presented below as of and for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	United States	Canada	Trinidad	Other International [1]	Total
2008					
Natural Gas	$ 3,497,620	$ 619,792	$ 285,184	$ 49,462	$ 4,452,058
Crude Oil, Condensate and Natural Gas Liquids	1,552,163	107,915	107,878	1,970	1,769,926
Gains on Mark-to-Market Commodity Derivative Contracts	597,911	-	-	-	597,911
Gathering, Processing and Marketing	164,535	-	-	-	164,535
Other, Net	147,204	(892)	(3,599)	-	142,713
Net Operating Revenues [2]	5,959,433	726,815	389,463	51,432	7,127,143
Depreciation, Depletion and Amortization	1,100,917	189,796	26,596	9,566	1,326,875
Operating Income (Expense)	3,183,547	306,967	286,600	(9,929)	3,767,185
Interest Income	1,589	2,703	2,641	1,793	8,726
Other Income (Expense)	7,961	(2,111)	18,868	(2,432)	22,286
Net Interest Expense	29,586	27,195	6,150	(11,273)	51,658
Income Before Income Taxes	3,163,511	280,364	301,959	705	3,746,539
Income Tax Provision (Benefit)	1,131,631	68,593	110,242	(846)	1,309,620
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,094,265	464,836	86,907	17,685	4,663,693
Total Property, Plant and Equipment, Net	10,771,911	2,298,823	539,576	46,992	13,657,302
Total Assets	12,668,763	2,421,979	735,387	125,097	15,951,226
2007					
Natural Gas	$ 2,220,892	$ 510,473	$ 248,553	$ 52,887	$ 3,032,805
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
Gathering, Processing and Marketing	73,539	-	-	-	73,539
Other, Net	52,510	(50)	(133)	1	52,328
Net Operating Revenues [2]	3,246,086	585,264	352,744	55,209	4,239,303
Depreciation, Depletion and Amortization	848,051	170,666	24,883	21,945	1,065,545
Operating Income	1,199,816	197,207	247,638	3,735	1,648,396
Interest Income	850	2,474	5,226	1,143	9,693
Other Income (Expense)	7,384	(4,348)	16,609	(88)	19,557
Net Interest Expense	20,262	20,391	6,148	(23)	46,778
Income Before Income Taxes	1,187,788	174,942	263,325	4,813	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	59,309	12,088,907

	United States	Canada	Trinidad	Other International (1)	Total
2006					
Natural Gas	$ 1,945,133	$ 529,294	$ 234,741	$ 83,752	$ 2,792,920
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
Gathering, Processing and Marketing	29,733	-	-	-	29,733
Other, Net	5,094	(3)	11	5,046	10,148
Net Operating Revenues (3)	2,897,799	593,674	345,688	91,480	3,928,641
Depreciation, Depletion and Amortization	623,311	143,368	26,623	23,787	817,089
Operating Income	1,324,215	277,009	250,470	51,859	1,903,553
Interest Income	17,159	4,861	4,697	-	26,717
Other Income (Expense)	12,872	(6,412)	18,925	144	25,529
Net Interest Expense	11,597	21,531	9,988	42	43,158
Income Before Income Taxes	1,342,649	253,927	264,104	51,961	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	95,281	9,402,160

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) EOG had no significant purchasers in 2008 or 2007 whose sales totaled 10 percent or more of consolidated Net Operating Revenues.
(3) 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.

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 price swap, collar and basis 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," as amended, 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 2008, 2007 and 2006, 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 2008, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $598 million, which included realized losses of $137 million. 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.

At December 31, 2008, the fair value of EOG's financial commodity derivative contracts was reflected in the Consolidated Balance Sheets as Current Assets - Assets From Price Risk Management Activities ($779 million), Other Assets ($57 million), Current Liabilities - Liabilities from Price Risk Management Activities ($4 million) and Other Liabilities ($8 million). At December 31, 2007, the fair value of EOG's financial commodity derivative contracts was reflected in the Consolidated Balance Sheets as Current Assets - Assets From Price Risk Management Activities ($101 million) and Current Liabilities - Liabilities From Price Risk Management Activities ($3 million).

Financial Collar Contracts. Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at December 31, 2008. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 is $10.00 per million British thermal units (MMBtu) and the average ceiling price is $12.32 per MMBtu.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55
July	40,000	9.40 - 9.45	9.43	11.60 - 11.70	11.65
August	40,000	9.47 - 9.52	9.50	11.68 - 11.80	11.74
September	40,000	9.50 - 9.55	9.52	11.73 - 11.85	11.79
October	40,000	9.58 - 9.63	9.61	11.83 - 11.95	11.89
November	40,000	9.88 - 9.93	9.91	12.30 - 12.40	12.35
December	40,000	9.87 - 10.30	10.09	12.55 - 12.71	12.63

Financial Price Swap Contracts. Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at December 31, 2008. The notional volumes are expressed in MMBtud and prices are expressed in $/MMBtu. The average price of EOG's natural gas financial price swap contracts for 2009 is $9.71 per MMBtu and for 2010 is $9.87 per MMBtu.

Natural Gas Financial Price Swap Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2009		
January (closed)	585,000	$10.76
February (closed)	585,000	10.74
March (closed)	585,000	10.50
April	610,000	9.24
May	610,000	9.16
June	610,000	9.21
July	610,000	9.29
August	610,000	9.34
September	610,000	9.36
October	610,000	9.42
November	610,000	9.66
December	610,000	9.98
2010		
January	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21
July	20,000	9.31
August	20,000	9.38
September	20,000	9.40
October	20,000	9.49
November	20,000	9.80
December	20,000	10.21

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at December 31, 2008. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap. The notional volumes are expressed in MMBtud and price differentials expressed in $/MMBtu.

Natural Gas Financial Basis Swap Contracts		
	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2009		
Second Quarter	65,000	$(2.54)
Third Quarter	65,000	(2.60)
Fourth Quarter	65,000	(3.03)
2010		
First Quarter	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

Credit Risk. 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 equal to the fair value of such contracts (see Note 12). 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, 2008 and 2007, no individual purchaser's net accounts receivable balance related to United States, Canada and the United Kingdom hydrocarbon sales accounted for 10% or more of the total balance. In 2008 and 2007, natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago.

At December 31, 2008 and 2007, EOG had an allowance for doubtful accounts of $13 million and $16 million, respectively, of which $11 million and $14 million, respectively, were associated with the Enron Corp. bankruptcies recorded in December 2001.

Substantially all of EOG's accounts receivable at December 31, 2008 and 2007 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, 2008, credit losses incurred on receivables by EOG have been immaterial.

12. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value in the accompanying balance sheets. Effective January 1, 2008, EOG adopted the provisions of SFAS No. 157, "Fair Value Measurements," for its financial assets and liabilities. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, SFAS No. 157 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. SFAS No. 157 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. In accordance with FSP 157-2, "Effective Date of FASB Statement No. 157," EOG has not applied the provisions of SFAS No. 157 to its asset retirement obligations or in the measurement of nonfinancial long-lived assets under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The following table provides fair value measurement information within the hierarchy for certain of EOG's financial assets and liabilities carried at fair value at December 31, 2008 and 2007 (in millions):

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
At December 31, 2008				
Financial Assets:				
Natural gas collars, price swaps and basis swaps	$ -	$ 836	$ -	$ 836
Financial Liabilities:				
Natural gas collars, price swaps and basis swaps	$ -	$ 12	$ -	$ 12
Foreign currency rate swap	$ -	$ 26	$ -	$ 26
At December 31, 2007				
Financial Assets:				
Crude oil and natural gas price swaps	$ -	$ 101	$ -	$ 101
Financial Liabilities:				
Crude oil and natural gas price swaps	$ -	$ 3	$ -	$ 3
Foreign currency rate swap	$ -	$ 58	$ -	$ 58

The estimated fair value of crude oil price swap and natural gas collar, price swap and basis swap contracts was based upon forward commodity price curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates.

13. 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 2008, 2007 and 2006, 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 $58 million, $60 million and $48 million in the United States operating segment during 2008, 2007 and 2006, respectively, and $2 million, $22 million and $7 million in the Canada operating segment during 2008, 2007 and

2006, respectively. Additionally, during 2008, EOG recorded pretax charges of $20 million and $6 million in the Trinidad and United Kingdom operating segments, respectively. 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 $107 million, $66 million and $53 million for 2008, 2007 and 2006, respectively.

14. 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 pursuant to SFAS No. 143, "Accounting for Asset Retirement Obligations," at December 31, 2008 and 2007 (in thousands):

	2008	2007
Carrying Amount at Beginning of Period	$ 211,124	$ 182,407
Liabilities Incurred	58,942	26,210
Liabilities Settled	(18,813)	(18,072)
Accretion	15,356	10,187
Revisions [1]	111,112	2,973
Foreign Currency Translations	(9,562)	7,419
Carrying Amount at End of Period	$ 368,159	$ 211,124
Current Portion	$ 19,459	$ 4,781
Noncurrent Portion	$ 348,700	$ 206,343

(1) Revisions to asset retirement obligations reflect increases in abandonment cost estimates.

The current and non current portions of EOG's asset retirement obligations are included in Current Liabilities - Other and Other Liabilities, respectively, on the Consolidated Balance Sheets.

15. 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. At December 31, 2008, EOG's equity interests in CNCL and N2000 were 12% and 10%, respectively.

At December 31, 2008, the investment in CNCL was $25 million. CNCL commenced ammonia production in June 2002. At December 31, 2008, CNCL had a long-term debt balance of $81 million, which is non-recourse to CNCL's shareholders. EOG would 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 2008, EOG recognized equity income of $7 million and received cash dividends of $1 million from CNCL.

At December 31, 2008, the investment in N2000 was $20 million. N2000 commenced ammonia production in August 2004. At December 31, 2008, N2000 had a long-term debt balance of $105 million, which is non-recourse to N2000's shareholders. EOG would 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 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 2008, EOG recognized equity income of $12 million and received cash dividends of $8 million from N2000.

16. Suspended Well Costs

EOG's net changes in suspended well costs for the years ended December 31, 2008, 2007 and 2006, in accordance with FSP No. 19-1, "Accounting for Suspended Well Costs," are presented below (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Balance at January 1	$ 148,881	$ 77,365	$ 27,868
Additions Pending the Determination of Proved Reserves	96,698	132,993	64,449
Reclassifications to Proved Properties	(120,110)	(23,716)	(10,474)
Charged to Dry Hole Costs	(22,116)	(18,232)	(3,901)
Foreign Currency Translations	(18,098)	6,105	(577)
Other	-	(25,634) (1)	-
Balance at December 31	$ 85,255	$ 148,881	$ 77,365

(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, 2008, 2007 and 2006 (in thousands, except well count):

	Year Ended December 31,		
	2008	2007	2006
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 31,784	$ 97,624	$ 50,589
Capitalized exploratory well costs that have been capitalized for a period greater than one year	53,471 (1)	51,257 (2)	26,776 (3)
Total	$ 85,255	$ 148,881	$ 77,365
Number of exploratory wells that have been capitalized for a period greater than one year	3	2	2

(1) Costs related to two shale projects in British Columbia, Canada (B.C.) ($35 million) and an outside operated, offshore Central North Sea project in the United Kingdom ($19 million). In the B.C. projects, further reserve evaluations will be made based on drilling and completion activities during 2009 and 2010. In addition, EOG is currently evaluating infrastructure alternatives for the B.C. shale projects. In the Central North Sea project, the operator submitted a field development plan to the Department of Energy and Climate Change during the fourth quarter of 2008.

(2) Costs related to a shale project in B.C. ($38 million) and an outside operated, offshore Central North Sea project in the United Kingdom ($13 million).

(3) Costs related to an outside operated, deepwater offshore Gulf of Mexico discovery ($4 million) and an outside operated, winter access only, Northwest Territories discovery in Northern Canada ($23 million).

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" (SFAS No. 69):

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" natural gas and liquids 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 and 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, production volumes and the length, both vertical and horizontal, of wells. Canadian reserves, as presented on a net basis, assume prices and legislated future royalty rates and EOG's estimate of future production volumes. Similarly, certain of EOG's Trinidad reserves are held under production sharing contracts where EOG's interest varies with prices and production volumes. Trinidad reserves, as presented on a net basis, assume prices 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 and Trinidadian reserves to be materially different from that presented.

Estimates of proved and proved developed reserves at December 31, 2008, 2007 and 2006 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, 2008, 2007 and 2006 covered producing areas containing 79%, 79% 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, 2008 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, 2008, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2008, as estimated by the engineering staff of EOG.

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Trinidad	Other International [(1)]	Total
NET PROVED RESERVES					
Natural Gas (Bcf) [(2)]					
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
Revisions of previous estimates	(110.3)	22.9	62.2	(4.2)	(29.4)
Purchases in place	31.0	15.0	-	12.2	58.2
Extensions, discoveries and other additions	1,384.4	60.6	-	-	1,445.0
Sales in place	(200.2)	-	-	-	(200.2)
Production	(436.0)	(81.1)	(80.4)	(6.0)	(603.5)
Net proved reserves at December 31, 2008	**4,889.0**	**1,237.2**	**1,198.1**	**14.9**	**7,339.2**

	United States	Canada	Trinidad	Other International [1]	Total
Liquids (MBbl) [3]					
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
Revisions of previous estimates	(1,592)	854	403	(20)	(355)
Purchases in place	6	-	184	58	248
Extensions, discoveries and other additions	67,877	919	-	-	68,796
Sales in place	(495)	-	-	-	(495)
Production	(19,971)	(1,344)	(1,161)	(20)	(22,496)
Net proved reserves at December 31, 2008	**205,846**	**10,795**	**8,326**	**65**	**225,032**
Bcf Equivalent (Bcfe) [2]					
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
Revisions of previous estimates	(119.9)	28.1	64.7	(4.3)	(31.4)
Purchases in place	31.1	15.0	1.1	12.5	59.7
Extensions, discoveries and other additions	1,791.6	66.1	-	-	1,857.7
Sales in place	(203.2)	-	-	-	(203.2)
Production	(555.8)	(89.2)	(87.4)	(6.1)	(738.5)
Net proved reserves at December 31, 2008	**6,124.0**	**1,302.0**	**1,248.1**	**15.3**	**8,689.4**

	United States	Canada	Trinidad	Other International [1]	Total
NET PROVED DEVELOPED RESERVES					
Natural Gas (Bcf) [2]					
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
December 31, 2008	3,544.7	1,103.7	889.0	14.9	5,552.3
Liquids (MBbl) [3]					
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
December 31, 2008	159,607	10,416	6,756	65	176,844
Bcf Equivalents (Bcfe) [2]					
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
December 31, 2008	4,502.3	1,166.2	929.6	15.3	6,613.4

(1) Includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) 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 and condensate or natural gas liquids.
(3) Thousand barrels; includes crude oil and 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, 2008 and 2007:

	2008	2007
Proved properties	$ 19,785,449	$ 16,299,661
Unproved properties	1,018,180	682,175
Total	20,803,629	16,981,836
Accumulated depreciation, depletion and amortization	(7,952,608)	(6,957,550)
Net capitalized costs [1]	**$ 12,851,021**	**$ 10,024,286**

(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, 2008, 2007 and 2006:

	United States	Canada	Trinidad	Other International [1]	Total
2008					
Acquisition Costs of Properties					
Unproved	$ 376,017	$ 141,080	$ 313	$ 3,438	$ 520,848
Proved	69,612	14,071	14,836	10,301	108,820
Subtotal	445,629	155,151	15,149	13,739	629,668
Exploration Costs	550,725	95,647	6,638	16,693	669,703
Development Costs [2]	3,405,627	281,480	99,384	7,166	3,793,657
Total	$ 4,401,981	$ 532,278	$ 121,171	$ 37,598	$ 5,093,028
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	33,104	589,740
Development Costs [3]	2,358,258	263,547	91,242	(1,417)	2,711,630
Total	$ 3,031,426	$ 385,616	$ 151,779	$ 30,546	$ 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	21,075	497,875
Development Costs [4]	1,744,301	339,602	79,712	17,945	2,181,560
Total	$ 2,304,081	$ 442,395	$ 136,649	$ 44,055	$ 2,927,180

(1) Other International primarily consist of EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(2) Includes Asset Retirement Costs of $107 million, $38 million, $29 million and $7 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(3) Includes Asset Retirement Costs of $22 million, $9 million, zero and zero for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(4) Includes Asset Retirement Costs of $10 million, $6 million, $1 million and $5 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

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, 2008, 2007 and 2006:

	United States	Canada	Trinidad	Other International (2)	Total
2008					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 5,049,783	$ 727,707	$ 393,062	$ 51,432	$ 6,221,984
Other	18,193	1,002	45	-	19,240
Total	5,067,976	728,709	393,107	51,432	6,241,224
Exploration Costs	157,400	16,605	5,911	13,970	193,886
Dry Hole Costs	43,215	12,408	(104)	(352)	55,167
Transportation Costs	260,628	9,819	247	3,396	274,090
Production Costs	682,230	136,084	41,973	7,697	867,984
Impairments	137,102	29,378	19,747	6,632	192,859
Depreciation, Depletion and Amortization	1,037,125	188,860	26,039	9,080	1,261,104
Income Before Income Taxes	2,750,276	335,555	299,294	11,009	3,396,134
Income Tax Provision	991,826	100,197	115,515	6,403	1,213,941
Results of Operations	$ 1,758,450	$ 235,358	$ 183,779	$ 4,606	$ 2,182,193
2007					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 3,026,929	$ 585,314	$ 352,877	$ 55,208	$ 4,020,328
Other	8,796	(105)	8	1	8,700
Total	3,035,725	585,209	352,885	55,209	4,029,028
Exploration Costs	116,152	15,500	7,577	11,216	150,445
Dry Hole Costs	83,160	5,349	19,350	7,523	115,382
Transportation Costs	136,630	8,880	-	6,726	152,236
Production Costs	454,164	137,003	45,634	3,381	640,182
Impairments	108,037	37,076	-	2,404	147,517
Depreciation, Depletion and Amortization	809,540	169,852	24,306	21,565	1,025,263
Income Before Income Taxes	1,328,042	211,549	256,018	2,394	1,798,003
Income Tax Provision	477,826	68,330	112,996	1,960	661,112
Results of Operations	$ 850,216	$ 143,219	$ 143,022	$ 434	$ 1,136,891
2006					
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids Revenues	$ 2,528,712	$ 593,677	$ 345,677	$ 86,434	$ 3,554,500
Other	1,552	(3)	11	461	2,021
Total	2,530,264	593,674	345,688	86,895	3,556,521
Exploration Costs	123,010	13,958	7,953	10,087	155,008
Dry Hole Costs	63,912	5,961	10,178	(484)	79,567
Transportation Costs	84,299	8,403	-	7,302	100,004
Production Costs	376,837	115,538	44,327	3,071	539,773
Impairments	89,374	18,884	-	-	108,258
Depreciation, Depletion and Amortization	598,545	141,926	26,100	23,444	790,015
Income Before Income Taxes	1,194,287	289,004	257,130	43,475	1,783,896
Income Tax Provision	429,052	83,277	102,986	22,714	638,029
Results of Operations	$ 765,235	$ 205,727	$ 154,144	$ 20,761	$ 1,145,867

(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, 2008.

(2) Other International primarily consist of EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and liquids reserves 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 natural gas and liquids reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

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

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's crude oil and natural gas reserves for the years ended December 31, 2008, 2007 and 2006:

	United States	Canada	Trinidad	Other International (1)	Total
2008					
Future cash inflows (2)	$ 30,251,481	$ 6,522,526	$ 2,073,962	$ 82,842	$ 38,930,811
Future production costs	(10,378,028)	(2,100,701)	(475,725)	(35,504)	(12,989,958)
Future development costs	(3,270,509)	(395,609)	(259,155)	(6,174)	(3,931,447)
Future income taxes	(4,789,311)	(761,525)	(401,264)	(15,038)	(5,967,138)
Future net cash flows	11,813,633	3,264,691	937,818	26,126	16,042,268
Discount to present value at 10% annual rate	(5,505,921)	(1,513,539)	(336,765)	(6,142)	(7,362,367)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 6,307,712	$ 1,751,152	$ 601,053	$ 19,984	$ 8,679,901
2007					
Future cash inflows (3)	$ 41,151,570	$ 8,783,187	$ 6,196,996	$ 133,844	$ 56,265,597
Future production costs	(11,449,082)	(2,766,329)	(630,556)	(29,022)	(14,874,989)
Future development costs	(2,716,181)	(493,772)	(385,406)	(8,049)	(3,603,408)
Future income taxes	(8,195,111)	(1,085,595)	(2,065,505)	(48,387)	(11,394,598)
Future net cash flows	18,791,196	4,437,491	3,115,529	48,386	26,392,602
Discount to present value at 10% annual rate	(9,326,881)	(2,002,808)	(1,276,573)	(4,718)	(12,610,980)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 9,464,315	$ 2,434,683	$ 1,838,956	$ 43,668	$ 13,781,622
2006					
Future cash inflows (4)	$ 22,960,379	$ 7,326,752	$ 4,674,862	$ 93,031	$ 35,055,024
Future production costs	(6,928,994)	(2,398,427)	(592,840)	(40,995)	(9,961,256)
Future development costs	(2,083,736)	(395,270)	(422,979)	(7,942)	(2,909,927)
Future income taxes	(4,096,634)	(988,737)	(1,450,026)	(22,047)	(6,557,444)
Future net cash flows	9,851,015	3,544,318	2,209,017	22,047	15,626,397
Discount to present value at 10% annual rate	(4,701,530)	(1,581,762)	(964,368)	(1,076)	(7,248,736)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 5,149,485	$ 1,962,556	$ 1,244,649	$ 20,971	$ 8,377,661

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

(2) Estimated natural gas prices used to calculate 2008 future cash inflows for the United States, Canada, Trinidad, the United Kingdom and China were $5.05, $6.25, $1.49, $8.73 and $3.66, respectively. Estimated liquid prices used to calculate 2008 future cash inflows for the United States, Canada, Trinidad, the United Kingdom and China were $27.02, $25.44, $33.98, $36.07 and $114.41, respectively.

(3) Estimated natural gas prices used to calculate 2007 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $6.79, $6.47, $4.29 and $10.05, respectively. Estimated liquids prices used to calculate 2007 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $78.13, $78.10, $86.11 and $84.20, respectively.

(4) Estimated natural gas prices used to calculate 2006 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $5.18, $5.22, $3.10 and $4.72, respectively. Estimated liquids prices used to calculate 2006 future cash inflows for the United States, Canada, Trinidad and the United Kingdom were $51.63, $50.90, $56.82 and $55.98, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2008:

	United States	Canada	Trinidad	Other International	Total
December 31, 2005	$ 7,311,319	$ 3,020,963	$ 1,163,628	$ 205,793	$ 11,701,703
Sales and transfers of oil and gas produced, net of production costs	(2,050,290)	(469,736)	(301,350)	(76,061)	(2,897,437)
Net changes in prices and production costs	(3,898,956)	(1,766,233)	164,417	(212,730)	(5,713,502)
Extensions, discoveries, additions and improved recovery, net of related costs	1,837,039	327,281	38,100	-	2,202,420
Development costs incurred	312,900	50,700	37,400	8,093	409,093
Revisions of estimated development cost	(26,149)	(663)	557	(2,316)	(28,571)
Revisions of previous quantity estimates	(280,488)	(176,733)	(741)	(11,825)	(469,787)
Accretion of discount	1,035,133	401,320	180,872	33,034	1,650,359
Net change in income taxes	1,247,841	655,261	(130,573)	103,571	1,876,100
Purchases of reserves in place	23,473	2,732	-	-	26,205
Sales of reserves in place	(17,449)	(6,746)	-	-	(24,195)
Changes in timing and other	(344,888)	(75,590)	92,339	(26,588)	(354,727)
December 31, 2006	5,149,485	1,962,556	1,244,649	20,971	8,377,661
Sales and transfers of oil and gas produced, net of production costs	(2,408,307)	(439,482)	(307,237)	(45,107)	(3,200,133)
Net changes in prices and production costs	3,397,803	747,389	961,686	76,223	5,183,101
Extensions, discoveries, additions and improved recovery, net of related costs	3,708,015	184,691	-	-	3,892,706
Development costs incurred	459,700	42,300	139,100	-	641,100
Revisions of estimated development cost	(2,547)	(56,336)	(57,498)	(70)	(116,451)
Revisions of previous quantity estimates	294,500	(135,562)	(57,680)	19,645	120,903
Accretion of discount	694,165	229,953	202,032	4,194	1,130,344
Net change in income taxes	(1,872,542)	(46,935)	(378,415)	(22,697)	(2,320,589)
Purchases of reserves in place	5,309	1,726	55,372	-	62,407
Sales of reserves in place	(47,151)	-	-	-	(47,151)
Changes in timing and other	85,885	(55,617)	36,947	(9,491)	57,724
December 31, 2007	9,464,315	2,434,683	1,838,956	43,668	13,781,622
Sales and transfers of oil and gas produced, net of production costs	(4,106,925)	(581,804)	(350,842)	(40,338)	(5,079,909)
Net changes in prices and production costs	(5,043,379)	(709,659)	(2,148,861)	(9,820)	(7,911,719)
Extensions, discoveries, additions and improved recovery, net of related costs	2,187,722	107,545	-	-	2,295,267
Development costs incurred	736,800	19,400	30,600	-	786,800
Revisions of estimated development cost	(5,329)	41,666	69,261	1,621	107,219
Revisions of previous quantity estimates	(184,671)	48,638	47,606	(22,611)	(111,038)
Accretion of discount	1,312,902	281,860	299,304	8,734	1,902,800
Net change in income taxes	1,676,106	141,767	909,920	31,340	2,759,133
Purchases of reserves in place	120,300	26,002	4,886	14,559	165,747
Sales of reserves in place	(277,781)	-	-	-	(277,781)
Changes in timing and other	427,652	(58,946)	(99,777)	(7,169)	261,760
December 31, 2008	**$ 6,307,712**	**$ 1,751,152**	**$ 601,053**	**$ 19,984**	**$ 8,679,901**

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

Unaudited Quarterly Financial Information
(In Thousands, Except Per Share Data)

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
2008				
Net Operating Revenues [(1)]	$ 1,134,018	$ 1,095,512	$ 3,263,886	$ 1,633,727
Operating Income	$ 380,720	$ 243,103	$ 2,392,183	$ 751,179
Income Before Income Taxes	$ 370,112	$ 247,383	$ 2,393,952	$ 735,092
Income Tax Provision	129,156	69,177	837,667	273,620
Net Income	240,956	178,206	1,556,285	461,472
Preferred Stock Dividends [(2)]	443	-	-	-
Net Income Available to Common Stockholders	$ 240,513	$ 178,206	$ 1,556,285	$ 461,472
Net Income Per Share Available to Common Stockholders [(3)]				
Basic	$ 0.98	$ 0.72	$ 6.30	$ 1.86
Diluted	$ 0.96	$ 0.71	$ 6.20	$ 1.84
Average Number of Common Shares				
Basic	245,430	246,536	247,155	247,672
Diluted	249,763	251,135	250,930	250,162
2007				
Net Operating Revenues [(1)]	$ 879,087	$ 1,079,162	$ 995,069	$ 1,285,985
Operating Income	$ 338,240	$ 465,481	$ 324,858	$ 519,817
Income Before Income Taxes	$ 335,321	$ 465,869	$ 318,598	$ 511,080
Income Tax Provision	117,654	158,816	114,595	149,885
Net Income	217,667	307,053	204,003	361,195
Preferred Stock Dividends [(2)]	875	990	1,637	3,161
Net Income Available to Common Stockholders	$ 216,792	$ 306,063	$ 202,366	$ 358,034
Net Income Per Share Available to Common Stockholders [(3)]				
Basic	$ 0.89	$ 1.26	$ 0.83	$ 1.46
Diluted	$ 0.88	$ 1.24	$ 0.82	$ 1.44
Average Number of Common Shares				
Basic	242,763	243,227	243,486	244,440
Diluted	246,677	247,261	247,425	248,537

(1) Certain reclassifications have impacted Net Operating Revenues. See Note 1 to Consolidated Financial Statements.
(2) Includes premium and fees associated with the repurchase of preferred stock in the first quarter of 2008 and the third and fourth quarters of 2007. See Note 3 to Consolidated Financial Statements.
(3) The sum of quarterly net income per share available to common stockholders may not agree with total year net income per share available to common stockholders as each quarterly computation is based on the weighted average of common shares outstanding.

Schedule II

EOG RESOURCES, INC.

VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2008, 2007 and 2006

(In Thousands)

Column A	Column B	Column C	Column D	Column E
Description	**Balance at Beginning of Year**	**Additions Charged to Costs and Expenses**	**Deductions From Reserves**	**Balance at End of Year**
2008				
Allowance deducted from Accounts Receivable	$ 16,019	$ 57	$ 2,945	$ 13,131
2007				
Allowance deducted from Accounts Receivable	$ 17,299	$ 16	$ 1,296	$ 16,019
2006				
Allowance deducted from Accounts Receivable	$ 21,806	$ 24	$ 4,531	$ 17,299

EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by (i) an asterisk (*) and are filed herewith; or (ii) a pound sign (#) and are not filed herewith, and, pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the registrant hereby agrees to furnish a copy of such exhibit to the SEC upon request.

Exhibit Number		Description
*3.1(a)	-	Restated Certificate of Incorporation, dated September 3, 1987.
3.1(b)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 5, 1993 (Exhibit 4.1(b) to EOG's Registration Statement on Form S-8, File No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 14, 1994 (Exhibit 4.1(c) to EOG's Registration Statement on Form S-8, File No. 33-58103, filed March 15, 1995).
3.1(d)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to EOG's Registration Statement on Form S-3, File No. 333-09919, filed August 9, 1996).
3.1(e)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to EOG's Registration Statement on Form S-3, File No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger Merging EOG Resources, Inc. into Enron Oil & Gas Company, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
3.1(h)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 13, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3, File No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 13, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3, File No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004).
3.1(k)	-	Amended Certificate of Designations of Series E Junior Participating Preferred Stock, dated March 7, 2005. (Exhibit 3.1(m) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
3.1(l)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
3.1(m)	-	Certificate of Elimination of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated March 6, 2008 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed March 6, 2008).

Exhibit Number		Description
3.2	-	Bylaws, as amended and restated effective as of January 4, 2008 (Exhibit 3.2 to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
4.1	-	Specimen of Certificate evidencing EOG's Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
4.2(a)	-	Rights Agreement, dated as of February 14, 2000, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 1 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.2(b)	-	Form of Right Certificate (Exhibit 3 to EOG's Registration Statement on Form 8-A, filed February 18, 2000).
4.2(c)	-	Amendment to Rights Agreement, dated as of December 13, 2001, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 2 to Amendment No. 1 to EOG's Registration Statement on Form 8-A/A, filed December 14, 2001).
4.2(d)	-	Letter, dated December 13, 2001, from First Chicago Trust Company of New York to EOG, resigning as rights agent, effective January 12, 2002 (Exhibit 3 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A, filed February 7, 2002).
4.2(e)	-	Amendment No. 2 to Rights Agreement, dated as of December 20, 2001, between EOG and First Chicago Trust Company of New York, as rights agent (Exhibit 4 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A, filed February 7, 2002).
4.2(f)	-	Letter, dated December 20, 2001, from EOG to EquiServe Trust Company, N.A., appointing EquiServe Trust Company, N.A. as successor rights agent, effective January 12, 2002 (Exhibit 5 to Amendment No. 2 to EOG's Registration Statement on Form 8-A/A, filed February 7, 2002).
4.2(g)	-	Amendment No. 3 to Rights Agreement, dated as of April 11, 2002, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed April 12, 2002) (SEC File No. 001-09743).
4.2(h)	-	Amendment No. 4 to Rights Agreement, dated as of December 10, 2002, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed December 11, 2002) (SEC File No. 001-09743).
4.2(i)	-	Amendment No. 5 to Rights Agreement, dated as of February 24, 2005, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.12 to EOG's Annual Report on Form 10-K for the year ended December 31, 2004).
4.2(j)	-	Amendment No. 6 to Rights Agreement, dated as of June 15, 2005, between EOG and EquiServe Trust Company, N.A., as rights agent (Exhibit 4.1 to EOG's Current Report on Form 8-K, filed June 21, 2005).
4.2(k)	-	Rights Agreement Certificate, dated February 11, 2008 (Exhibit 4.20 to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
4.3	-	Indenture, dated as of September 1, 1991, between Enron Oil & Gas Company (predecessor to EOG) and The Bank of New York Mellon Trust Company, N.A. (as successor in interest to JPMorgan Chase Bank, N.A. (formerly, Texas Commerce Bank National Association)), as Trustee (Exhibit 4(a) to EOG's Registration Statement on Form S-3, File No. 33-42640, filed September 6, 1991).
4.4(a)	-	Officers' Certificate Establishing 6.125% Senior Notes due 2013 and 6.875% Senior Notes due 2018, dated September 30, 2008 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 30, 2008).

Exhibit Number		Description
4.4(b)	-	Form of Global Note with respect to the 6.125% Senior Notes due 2013 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 30, 2008).
4.4(c)	-	Form of Global Note with respect to the 6.875% Senior Notes due 2018 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed September 30, 2008).
4.5(a)	-	Officers' Certificate Establishing 5.875% Senior Notes due 2017 of EOG, dated September 10, 2007 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 10, 2007).
4.5(b)	-	Form of Global Note with respect to the 5.875% Senior Notes due 2017 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 10, 2007).
#4.6(a)	-	Certificate, dated April 3, 1998, of the Senior Vice President and Chief Financial Officer of Enron Oil & Gas Company (predecessor to EOG) establishing the terms of the 6.65% Notes due April 1, 2028.
#4.6(b)	-	Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
#4.7(a)	-	Indenture, dated as of November 15, 2001, between EOG Company of Canada, as Issuer, and Citibank, N.A., as Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.7(b)	-	First Supplemental Indenture, dated as of April 2, 2002, to the Indenture, dated as of November 15, 2001, between EOG Company of Canada, as Issuer, and Citibank, N.A., as Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.8	-	Indenture, dated as of March 1, 2004, between EOG Resources Canada Inc., as Issuer, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 4.75% Senior Notes due 2014 of EOG Resources Canada Inc.
10.1(a)	-	EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 8, 2008 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(b)	-	First Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 4, 2008 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008).
10.1(c)	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(d)	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(e)	-	Form of Nonemployee Director Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(f)	-	Form of Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(g)	-	Form of Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.6 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(h)	-	Form of Nonemployee Director Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.7 to EOG's Current Report on Form 8-K, filed May 14, 2008).

Exhibit Number		Description
*10.2(a)	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan – Plan Document, effective as of December 16, 2008.
*10.2(b)	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan – Adoption Agreement, dated as of December 16, 2008.
10.3(a)	-	Amended and Restated Enron Oil & Gas Company 1994 Stock Plan (Exhibit 4.3 to EOG's Registration Statement on Form S-8, File No. 33-58103, filed March 15, 1995).
10.3(b)	-	Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 12, 1995 (Exhibit 4.3(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 1995) (SEC File No. 001-09743).
10.3(c)	-	Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 10, 1996 (Exhibit 4.3(a) to EOG's Registration Statement on Form S-8, File No. 333-20841, filed January 31, 1997).
10.3(d)	-	Third Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 9, 1997 (Exhibit 4.3(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 1997) (SEC File No. 001-09743).
10.3(e)	-	Fourth Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of May 5, 1998 (Exhibit 4.3(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998) (SEC File No. 001-09743).
10.3(f)	-	Fifth Amendment to Amended and Restated Enron Oil & Gas Company 1994 Stock Plan, dated effective as of December 8, 1998 (Exhibit 4.3(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1998) (SEC File No. 001-09743).
10.3(g)	-	Sixth Amendment to Amended and Restated EOG Resources, Inc. 1994 Stock Plan, dated effective as of May 8, 2001 (Exhibit 10.1(g) to EOG's Annual Report on Form 10-K for the year ended December 31, 2001) (SEC File No. 001-09743).
10.3(h)	-	Seventh Amendment to Amended and Restated EOG Resources, Inc. 1994 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.1(h) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.4(a)	-	EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, as amended and restated effective May 7, 2002 (Exhibit A to EOG's Proxy Statement, filed March 28, 2002, with respect to EOG's 2002 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.4(b)	-	First Amendment to EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, dated effective as of December 30, 2005 (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.5(a)	-	EOG Resources, Inc. 1992 Stock Plan, as amended and restated effective May 4, 2004 (Exhibit B to EOG's Proxy Statement, filed March 29, 2004, with respect to EOG's 2004 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.5(b)	-	First Amendment to EOG Resources, Inc. 1992 Stock Plan, dated effective as of December 30, 2005 (Exhibit 10.3(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005).
10.6(a)	-	Executive Employment Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.1 to EOG's Current Report on Form 8-K filed, June 21, 2005).

Exhibit Number		Description
10.6(b)	-	Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of June 15, 2005 (Exhibit 99.6 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(a)	-	Executive Employment Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.3 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.7(b)	-	Amended and Restated Change of Control Agreement between EOG and Loren M. Leiker, effective as of June 15, 2005 (Exhibit 99.8 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.8(a)	-	Executive Employment Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.4 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.8(b)	-	Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.9 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.9	-	Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.10(a)	-	Executive Employment Agreement between EOG and Frederick J. Plaeger, II, effective as of April 23, 2007 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.10(b)	-	Change of Control Agreement between EOG and Frederick J. Plaeger, II, effective as of April 23, 2007 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.11	-	EOG Resources, Inc. Change of Control Severance Plan, as amended and restated effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005).
10.12	-	EOG Resources, Inc. Executive Officer Annual Bonus Plan (Exhibit C to EOG's Proxy Statement, filed March 29, 2001, with respect to EOG's 2001 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.13(a)	-	Revolving Credit Agreement, dated as of June 28, 2005, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.13(b)	-	First Amendment to Revolving Credit Agreement, dated as of June 21, 2006, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.13(c)	-	Second Amendment to Revolving Credit Agreement, dated as of May 18, 2007, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.13(d)	-	Third Amendment to Revolving Credit Agreement, dated as of September 14, 2007, among EOG, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other financial institutions party thereto (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
*12	-	Computation of Ratio of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
*21	-	Subsidiaries of EOG, as of December 31, 2008.
*23.1	-	Consent of DeGolyer and MacNaughton.
*23.2	-	Opinion of DeGolyer and MacNaughton dated February 2, 2009.

Exhibit Number		**Description**
*23.3	-	Consent of Deloitte & Touche LLP.
*24	-	Powers of Attorney.
*31.1	-	Section 302 Certification of Annual Report of Principal Executive Officer.
*31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
*32.1	-	Section 906 Certification of Annual Report of Principal Executive Officer.
*32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.

SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: February 25, 2009

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities with EOG Resources, Inc. indicated and on the 25th day of February, 2009.

Signature	Title
/s/ MARK G. PAPA (Mark G. Papa)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
*GEORGE A. ALCORN (George A. Alcorn)	Director
*CHARLES R. CRISP (Charles R. Crisp)	Director
*JAMES C. DAY (James C. Day)	Director
*H. LEIGHTON STEWARD (H. Leighton Steward)	Director
*DONALD F. TEXTOR (Donald F. Textor)	Director
*FRANK G. WISNER (Frank G. Wisner)	Director

*By /s/ MICHAEL P. DONALDSON
(Michael P. Donaldson)
(Attorney-in-fact for persons indicated)