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, 2011

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

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 whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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, 2011: $28,070,598,553.

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, 269,085,607 shares outstanding as of February 17, 2012.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2012 Annual Meeting of Stockholders to be filed within 120 days after December 31, 2011 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 crude oil and natural gas primarily in major producing basins in the United States of America (United States or U.S.), Canada, The Republic of Trinidad and Tobago (Trinidad), the United Kingdom (U.K.), The People's Republic of China (China), the Argentine Republic (Argentina) 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 EOG's 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, 2011, EOG's total estimated net proved reserves were 2,054 million barrels of oil equivalent (MMBoe), of which 517 million barrels (MMBbl) were crude oil and condensate reserves, 228 MMBbl were natural gas liquids reserves and 7,851 billion cubic feet (Bcf), or 1,309 MMBoe, were natural gas reserves (see Supplemental Information to Consolidated Financial Statements). At such date, approximately 85% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States, 9% in Canada and 6% in Trinidad. Crude oil equivalent volumes are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet (Mcf) of natural gas.

As of December 31, 2011, EOG employed approximately 2,550 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 and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis. EOG is focused on cost-effective utilization of advanced technology associated with three-dimensional seismic and microseismic data, the development of reservoir simulation models, the use of improved drill bits, mud motors and mud additives for horizontal drilling, formation evaluation, and horizontal 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. 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 crude oil and natural gas exploration and production related. For financial information about our reportable segments (including financial information by segment geographic area), see Note 10 to Consolidated Financial Statements. For information regarding the risks associated with EOG's foreign operations, see Item 1A. Risk Factors.

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, with a current focus on liquids-rich plays.

At December 31, 2011, 39% of EOG's net proved reserves in the United States and Canada (on a crude oil equivalent basis) were crude oil and condensate and natural gas liquids and 61% were natural gas reserves. 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 and resource plays to its broad portfolio. The following is a summary of significant developments during 2011 and certain 2012 plans for EOG's United States and Canada operations.

United States. The liquids-rich Eagle Ford Shale has proven to be among EOG's most economically attractive resource plays to date. The Eagle Ford has well-defined crude oil, wet gas and dry gas trends. EOG's total acreage position in all three hydrocarbon trends totals 647,000 net acres. EOG has focused its drilling on its highly productive 572,000 net acreage position within the oil window where EOG has drilled a cumulative 356 net wells. EOG's strategy is to maintain its entire ownership interests and not to dilute its position by taking on a joint venture partner in this play. EOG is the largest oil producer in the Eagle Ford where its net production in 2011 was 30.2 thousand barrels per day (MBbld) of crude oil and condensate, 3.9 MBbld of natural gas liquids and 21 million cubic feet per day (MMcfd) of natural gas. This represents more than a six-fold, year-over-year increase in production. EOG drilled 269 net wells in 2011 and plans to drill and complete approximately 280 net wells in 2012.

In 2011, EOG increased activity in the liquids-rich Barnett Shale Combo play of the Fort Worth Basin where total production grew by approximately 105% above 2010 levels, including a 107% increase in liquids production. During the year, EOG completed 269 net Barnett Combo wells and increased its drilling potential in this liquids-rich play by expanding the core area from approximately 175,000 to approximately 200,000 net acres. EOG's total 2011 Barnett Shale average net daily production increased to approximately 37.7 MBbld of crude oil and condensate and natural gas liquids and 403 MMcfd of natural gas. For 2012, EOG will continue to focus on this play with plans to complete to sales an additional 200 net Barnett Shale Combo wells. In the natural gas portion of the Barnett Shale, EOG plans to complete to sales approximately 35 net wells. The rich natural gas from the majority of these wells will be processed to recover natural gas liquids. With a large acreage position of approximately 506,000 net acres in the Barnett Shale and a history of strong drilling results, EOG expects to continue to be an active driller in the Fort Worth Basin Barnett Shale for many years.

EOG maintained a strong and consistent development program throughout the Rocky Mountain area in 2011. EOG continued its development programs in the Williston, DJ and Uinta basins, drilling 79 net wells, 36 net wells and 33 net wells, respectively. EOG also resumed exploration and development activities in the Powder River Basin during 2011, drilling six net wells. Net average production for the entire Rocky Mountain area for 2011 was 46.6 MBbld of crude oil and condensate and natural gas liquids, an increase of 13% over the prior year. Natural gas production was down 17% from 2010 levels primarily due to divestitures and de-emphasized natural gas drilling. EOG holds approximately 1.6 million net acres in the Rocky Mountain area. For 2012, EOG intends to maintain a steady development program throughout the Rocky Mountain area where it plans to drill 123 net wells.

In 2011, EOG drilled and participated in 56 net wells in the Permian Basin to test the Leonard-Avalon Shale, Bone Spring and Wolfcamp formations. EOG is well positioned in these three established plays: the Leonard-Avalon Shale and Bone Spring plays in the Delaware Basin and the Wolfcamp Shale in the Midland Basin. Net production for the year 2011 averaged 10.5 MBbld of crude oil and condensate and natural gas liquids and 49 MMcfd of natural gas. After divestitures in 2011, EOG now controls approximately 480,000 net acres throughout the Permian Basin, with approximately 130,000 acres within the Wolfcamp Shale formation and 106,000 acres within the limits of the Bone Spring and Leonard-Avalon Shale formations. In 2012, EOG plans to continue the development, expansion and enhancement of the Wolfcamp, Leonard-Avalon and Bone Spring plays, by drilling 112 net wells, while continuing to look for new liquids-rich plays.

In 2011, EOG continued to expand its activities in the Mid-Continent area with continued growth and extension of its Western Anadarko Basin core area. For the year, EOG averaged net production of 7.1 MBbld of crude oil and condensate and natural gas liquids and 52 MMcfd of natural gas. Total crude oil and condensate and natural gas liquids volumes increased 22% in 2011 compared to 2010. In 2011, EOG continued its successful horizontal exploitation of the Cleveland sandstone, drilling 11 net wells with initial average gross production rates of approximately 350 barrels per day (Bbld) of crude oil and condensate and natural gas liquids per well. Since 2002, EOG has drilled over 230 net wells in this play and holds approximately 100,000 net acres throughout the trend. In the recently discovered Marmaton Sandstone play, where it holds approximately 80,000 net acres, EOG drilled a total of 18 net wells in 2011 with an initial average gross production rate of 550 Bbld of crude oil and condensate and natural gas liquids per well. In 2012, approximately 40 net wells are planned in order to further exploit these liquids-rich plays.

In the South Texas area, EOG drilled 47 net wells in 2011. Net production during 2011 averaged 6.4 MBbld of crude oil and condensate and natural gas liquids and 151 MMcfd of natural gas. EOG's activity was focused in Webb, Zapata, San Patricio, Nueces, Brooks and Kenedy counties. EOG will continue to focus on drilling liquids-rich wells in the Lobo and Roleta trends, the Frio and Vicksburg trends and the Nueces Wilcox trend. EOG holds approximately 364,500 net acres in South Texas. Approximately 43 net wells are planned for South Texas during 2012. EOG's Gulf of Mexico production of crude oil, condensate and natural gas liquids averaged approximately 75 Bbld for the year ended December 31, 2011. Thus, EOG's offshore operations in the Gulf of Mexico are immaterial in relation to EOG's overall operations and production; moreover, EOG does not have any plans for future offshore drilling in the Gulf of Mexico.

In the Upper Gulf Coast region, EOG drilled 47 net wells and net production averaged 227 MMcfd of natural gas and 1.0 MBbld of crude oil and condensate and natural gas liquids in 2011. The Haynesville and Bossier Shale plays located near the Texas-Louisiana border continue to be core natural gas assets for EOG. The drilling program has increased from 13 net wells in 2009 to 40 net wells in 2011. EOG expanded the Texas "sweet spot" in 2011 with excellent well results in southern Nacogdoches and Angelina counties. EOG now controls 175,000 net acres in this play, and most of this acreage is within a well-defined productive sweet spot. EOG holds a total of approximately 384,000 net acres in the Upper Gulf Coast region. Due to low natural gas prices, EOG plans to reduce activity and drill approximately 25 net wells in the Upper Gulf Coast region in 2012, including 15 net wells in the Haynesville.

During 2011, EOG continued the development of its Pennsylvania Marcellus Shale asset and drilled a total of 27 net wells. Nine net wells were drilled in Bradford County in northeastern Pennsylvania, and seven net wells were completed. The remaining 18 net wells were drilled in north central Pennsylvania, as part of EOG's joint venture with Seneca Resources Corporation where EOG is operator and holds a 50% working interest. EOG's net natural gas production averaged 33 MMcfd in 2011, up from 12 MMcfd in 2010. EOG currently holds in excess of 200,000 net acres in the Pennsylvania Marcellus Shale and plans to drill an estimated 35 net wells during 2012.

At December 31, 2011, EOG held approximately 3.6 million net undeveloped acres in the United States.

During 2011, EOG continued the expansion of its gathering and processing activities in the Barnett Shale of North Texas and the Bakken and Three Forks plays of North Dakota. EOG also installed field gathering and conditioning facilities in the Eagle Ford play of South Texas. EOG-owned natural gas processing capacity at December 31, 2011 in the Barnett Shale and Eagle Ford was 120 MMcfd and 135 MMcfd, respectively.

During June 2011, EOG sold its Stanley, North Dakota, condensate recovery unit and 76-mile, 12-inch diameter "dense phase" natural gas pipeline. In connection with the sale, EOG entered into an agreement with the buyer to reserve capacity in both the condensate recovery unit and the pipeline. The pipeline connects with the Alliance Pipeline which transports natural gas to the Chicago, Illinois, area.

Additionally, in support of its operations in the Williston Basin, EOG increased utilization of its crude oil loading facility near Stanley, North Dakota, to transport its oil production and oil purchased from third-party producers. Using this facility during 2011, EOG loaded 200 unit trains (each unit train typically consists of 100 cars and has a total aggregate capacity of approximately 68,000 barrels of crude oil) with crude oil for transport to Stroud, Oklahoma, and certain destinations on the U.S. Gulf Coast. In Stroud, Oklahoma, EOG owns a crude oil off-loading facility and a pipeline to transport the crude oil to the Cushing, Oklahoma, trading hub. Together, these facilities have the capacity to load/unload approximately 70 MBbld of crude oil.

In the South Texas Eagle Ford, EOG established a crude oil loading facility in Harwood, Texas, that became operational in April 2011. At this facility, crude oil is loaded onto unit trains of approximately 70 cars each, with capacity of approximately 46,000 barrels per train, and is shipped to destinations on the U.S. Gulf Coast. During 2011, a total of 45 shipments were made from the Harwood facility.

In order to access more diverse markets for its crude-by-rail shipments, during 2011 EOG began construction of a crude oil unloading facility in St. James, Louisiana, where sales are based upon the Light Louisiana Sweet price. This facility, which is scheduled to be operational in the second quarter of 2012, will have a capacity of approximately 100 MBbld, and be able to accommodate multiple trains at a single time.

EOG believes that its crude-by-rail facilities uniquely position it to direct its crude oil shipments via rail car from North Dakota and Texas to the most favorable markets.

Since 2008, EOG has been operating its own sand mine and sand processing plant located in Hood County, Texas, helping to fulfill EOG's sand needs in the Barnett Shale Combo play.

During 2011, EOG increased its sand mining and processing operations to supply sand for its well completion operations. EOG purchased a second processing plant in Hood County, Texas, in 2011, and began regular shipments of EOG-owned unprocessed sand from Wisconsin. After final processing at the Hood County facility, the sand is being utilized in key EOG plays.

During December 2011, EOG completed and placed in operation its new state-of-the-art Chippewa Falls, Wisconsin, sand plant to process sand from a nearby EOG-owned sand mine. The first unit train of processed sand was dispatched from Chippewa Falls at the beginning of January 2012. The majority of the initial trains are destined for a new EOG sand facility in Refugio, Texas. One to two sand unit trains of approximately 100 cars each are expected to arrive at Refugio every week as operations in Chippewa Falls ramp up. From there, the sand will be shipped primarily to the South Texas Eagle Ford play.

Canada. EOG conducts operations through its wholly-owned subsidiary, EOG Resources Canada Inc. (EOGRC), from its offices in Calgary, Alberta. During 2011, EOGRC continued its focus on horizontal crude oil growth, mainly through its drilling activity in Waskada, Manitoba. Other drilling activity was directed to acreage retention in its bigger target horizontal natural gas play in the Horn River Basin of British Columbia. During 2011, EOGRC drilled or participated in 101 net wells, all of which were horizontal wells. Correspondingly, net crude oil and condensate and natural gas liquids production increased by 16% to 8.8 MBbld. Net natural gas production decreased 34% to 132 MMcfd, reflecting a de-emphasis on gas drilling and EOGRC's sale of several shallow gas properties in late 2010. The focus on crude oil production growth will continue in 2012 with 133 net wells planned in a combination of plays from the continued development in Manitoba and new targets in Alberta. EOG plans to drill seven net wells in the Horn River Basin for acreage retention in 2012.

At December 31, 2011, EOGRC held approximately 749,000 net undeveloped acres in Canada.

In March 2011, EOGRC purchased an additional 24.5% interest in the proposed Pacific Trail Pipelines (PTP) for $25.2 million. The PTP is intended to link western Canada's natural gas producing regions to the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal). A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally, in March 2011, EOGRC and an affiliate of Apache Corporation (Apache), through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage. In the first quarter of 2011, EOGRC and Apache awarded a front-end engineering and design contract to a global engineering company with the final report expected in the second half 2012. In October 2011, the Canadian National Energy Board granted a 20-year export license to ship LNG from the Kitimat LNG Terminal to international markets.

Operations Outside the United States and Canada

EOG has operations offshore Trinidad, the U.K. North Sea and East Irish Sea, the China Sichuan Basin and the Neuquén Basin of Argentina, and is evaluating additional exploration, development and exploitation opportunities in these and other select international areas.

Trinidad. EOG, through several of its subsidiaries, including EOG Resources Trinidad Limited,

- holds an 80% working interest in the South East Coast Consortium (SECC) Block offshore Trinidad, except in the Deep Ibis area in which EOG's working interest decreased as a result of a third-party farm-out agreement;
- holds an 80% working interest in the exploration and production license covering the Pelican Field and its related facilities;
- holds a 50% working interest in the exploration and production license covering the EMZ Area offshore Trinidad as a result of a third party farm-out agreement which was executed in the fourth quarter of 2011;
- holds a 100% working interest in a production sharing contract with the Government of Trinidad and Tobago for each of the Modified U(a) Block, Modified U(b) Block and Block 4(a);
- 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); and
- owns a 10% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited (N2000).

Several fields in the SECC Block, Modified U(a) Block and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing natural gas and crude oil and condensate. In Block 4(a), EOG drilled and completed six development wells in the Toucan Field and one in the Sercan Field in 2011. Production from both the Toucan Field and EMZ Area began in February 2012 to supply natural gas under a contract with the National Gas Company of Trinidad and Tobago (NGC). EOG sourced the natural gas for this contract from its existing fields until the Toucan Field began producing.

Natural gas from EOG's Trinidad operations currently is sold to NGC or its subsidiary. Certain agreements with NGC require EOG's Trinidad operations to deliver in 2012 approximately 520 MMcfd (370 MMcfd, net) of natural gas, under current economic conditions. EOG intends to fulfill these natural gas delivery obligations by using production from existing proved reserves. Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago.

In 2011, EOG's average net production from Trinidad was 344 MMcfd of natural gas and 3.4 MBbld of crude oil and condensate.

At December 31, 2011, EOG held approximately 39,000 net undeveloped acres in Trinidad.

United Kingdom. EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), owns a 25% non-operating working interest in a portion of Block 49/16a, located in the Southern Gas Basin of the North Sea. During 2011, production continued from the Valkyrie field in this block.

EOGUK also owns 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.

In 2006, EOGUK participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. EOG has a 25% non-operating interest in this block. A successful Columbus prospect appraisal well was drilled during the third quarter of 2007. The field operator submitted a revised field development plan to the U.K. Department of Energy and Climate Change (DECC) during the second quarter of 2011 and anticipates receiving approval of this plan in the first half of 2012. The operator and partners are continuing to negotiate processing and transportation terms with export infrastructure owners.

In 2009, EOGUK drilled a successful exploratory well in its East Irish Sea Blocks 110/7b and 110/12a. Well 110/12-6, in which EOGUK has a 100% working interest, was an oil discovery and was designated the Conwy field. In 2010, EOGUK added an adjoining field in its East Irish Sea block, designated Corfe, to its overall development plans. During 2011, offshore facilities fabrication began, line pipe was fabricated and all principal facilities and drilling contracts were signed. Field development plans for the Conwy and Corfe fields were submitted to the DECC during the first quarter of 2011. Regulatory approval of both plans is expected during the first quarter of 2012. Installation of facilities, pipelines and drilling of development wells are planned for 2012, with initial production expected during the first quarter of 2013. The licenses for the East Irish Sea blocks were awarded to EOGUK in 2007.

In 2011, production averaged 3 MMcfd of natural gas, net, in the United Kingdom.

At December 31, 2011, EOG held approximately 95,000 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, China. In October 2008, EOG obtained the rights to shallower zones on the acreage acquired. During the first quarter of 2011, EOG completed one horizontal well.

In 2011, production averaged 10 MMcfd of natural gas, net, in China.

At December 31, 2011, EOG held approximately 131,000 net acres in China.

Argentina. During 2011, EOG signed two exploration contracts and one farm-in agreement covering approximately 100,000 net acres in the Neuquén Basin in Neuquén Province, Argentina. During the third quarter of 2011, EOG performed exploration activity on a portion of this acreage in preparation for drilling a well targeting the Vaca Muerta oil shale in the Aguada del Chivato Block. EOG began drilling this well in January 2012. In the first quarter of 2012, EOG plans to participate in drilling a second well in the Bajo del Toro Block targeting the Vaca Muerta oil shale.

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

Marketing

Wellhead Marketing. 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 2011, EOG's United States and Canada wellhead natural gas production was 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 approximated the prices received for natural gas sold on the spot market. In 2012, the pricing mechanism for such production is expected to remain the same.

In 2011, 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 United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2012.

In 2011, all wellhead natural gas volumes from the United Kingdom were sold on the spot market. The 2012 marketing strategy for the wellhead natural gas volumes from the United Kingdom is expected to remain the same.

In 2011, 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 2012.

In certain instances, EOG purchases and sells third-party crude oil and natural gas in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities.

During 2011, a single purchaser accounted for 10.1% of EOG's total wellhead crude oil and condensate, natural gas liquids and natural gas revenues and gathering, processing and marketing 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, crude oil and condensate, natural gas liquids and natural gas. The table also presents crude oil equivalent volumes which are determined using the ratio of 1.0 Bbl of crude oil and condensate or natural gas liquids to 6.0 Mcf of natural gas for each of the years ended December 31, 2011, 2010 and 2009.

Year Ended December 31	**2011**	**2010**	**2009**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States:			
Eagle Ford	30.2	4.1	-
Barnett	15.2	6.8	2.8
Other	56.6	52.3	45.1
United States	102.0	63.2	47.9
Canada	7.9	6.7	4.1
Trinidad	3.4	4.7	3.1
Other International (2)	0.1	0.1	0.1
Total	**113.4**	**74.7**	**55.2**
Natural Gas Liquids Volumes (MBbld) (1)			
United States:			
Eagle Ford	3.9	0.2	-
Barnett	22.6	16.3	10.3
Other	15.0	13.0	12.2
United States	41.5	29.5	22.5
Canada	0.9	0.9	1.1
Total	**42.4**	**30.4**	**23.6**
Natural Gas Volumes (MMcfd) (1)			
United States:			
Eagle Ford	21	4	-
Barnett	403	404	400
Other	689	725	734
United States	1,113	1,133	1,134
Canada	132	200	224
Trinidad	344	341	273
Other International (2)	13	14	14
Total	**1,602**	**1,688**	**1,645**
Crude Oil Equivalent Volumes (MBoed) (3)			
United States:			
Eagle Ford	37.7	5.0	-
Barnett	105.0	90.5	79.8
Other	186.4	186.0	179.6
United States	329.1	281.5	259.4
Canada	30.7	40.9	42.6
Trinidad	60.7	61.5	48.5
Other International (2)	2.2	2.5	2.4
Total	**422.7**	**386.4**	**352.9**
Total MMBoe (3)	**154.3**	**141.1**	**128.8**

Year Ended December 31		2011		2010		2009
Average Crude Oil and Condensate Prices ($/Bbl) (4)						
United States	$	92.92	$	74.88	$	54.42
Canada		91.92		72.66		57.72
Trinidad		90.62		68.80		50.85
Other International (2)		100.11		73.11		53.07
Composite		**92.79**		**74.29**		**54.46**
Average Natural Gas Liquids Prices ($/Bbl) (4)						
United States	$	50.37	$	41.68	$	30.03
Canada		52.69		43.40		30.49
Composite		**50.41**		**41.73**		**30.05**
Average Natural Gas Prices ($/Mcf) (4)						
United States	$	3.92	$	4.30	$	3.72
Canada		3.71		3.91		3.85
Trinidad		3.53		2.65		1.73
Other International (2)		5.62		4.90		4.34
Composite		**3.83**		**3.93**		**3.42**

(1) Thousand barrels per day or million cubic feet per day, as applicable.

(2) Other International includes EOG's United Kingdom and China operations.

(3) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, natural gas liquids and natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

(4) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 11 to Consolidated Financial Statements).

Competition

EOG competes with major integrated oil and gas companies, government-affiliated 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 contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market crude oil and natural gas. 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 certain respects, such as 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 crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Regulation

United States Regulation of Crude Oil and Natural Gas Production. Crude oil and natural gas production operations are subject to various types of regulation, including regulation in the United States by federal and state 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), the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), all 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 BSEE.

BLM and BOEM 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 BOEM or BSEE). Such offshore operations are subject to numerous regulatory requirements, including the need for prior BOEM and/or BSEE 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; regulations governing the plugging and abandonment of offshore wells; and the requirements for removal of all production facilities. Under certain circumstances, the BOEM or BSEE may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect EOG's interests.

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 Federal Energy Regulatory Commission (FERC). Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and natural gas liquids by EOG are made at unregulated market prices.

EOG owns 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 materially and adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's 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 oil and gas industry are considered from time to time by Congress, the state legislatures, the FERC and 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 oil and gas industry historically has been very heavily regulated; therefore, there is no assurance that the approach currently being followed by such legislative bodies and regulatory agencies and courts will continue indefinitely.

Canadian Regulation of Crude Oil and Natural Gas Production. The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. These regulatory authorities may impose regulations on or otherwise intervene in the oil and gas industry with respect to taxes and factors affecting prices, 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 oil and gas industry could reduce demand for these commodities or increase EOG's costs and, therefore, 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 government 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 EOG's revenues, earnings and cash flow.

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 crude oil and natural gas exploration, development and production operations. These laws and regulations 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 and, under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. EOG also could incur costs related to the clean-up of third-party 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 third-party sites. 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. Moreover, EOG is subject to the U.S. Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions and may in the future, as discussed further below, be subject to federal, state and local laws and regulations regarding hydraulic fracturing.

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, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such 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, financial condition and results of operations.

Climate Change. Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, recent U.S. EPA rulemaking may result in the regulation of GHGs as pollutants under the federal Clean Air Act. EOG supports efforts to understand and address the contribution of human activities to global climate change through the application of sound scientific research and analysis. Moreover, EOG believes that its strategy to reduce GHG emissions throughout its operations is in the best interest of the environment and is a generally good business practice.

EOG has developed a system that is utilized in calculating GHG emissions from its operating facilities. This emissions management system calculates emissions based on recognized regulatory methodologies, where applicable, and on commonly accepted engineering practices. EOG is now reporting GHG emissions for facilities covered under the U.S. EPA's Mandatory Reporting of Greenhouse Gases Rule published on October 30, 2009. EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Hydraulic Fracturing. Most onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. There have been various proposals to regulate hydraulic fracturing at the federal level. Hydraulic fracturing technology, which has been used by the oil and gas industry for more than 60 years and is constantly being enhanced, enables EOG to produce crude oil and natural gas from formations that would otherwise not be recovered. Specifically, hydraulic fracturing is a process in which pressurized fluid is pumped into underground formations to create tiny fractures or spaces that allow crude oil and natural gas to flow from the reservoir into the well so that it can be brought to the surface. Hydraulic fracturing generally takes place thousands of feet underground, a considerable distance below any drinking water aquifers, and there are impermeable layers of rock between the area fractured and the water aquifers. The makeup of the fluid used in the hydraulic fracturing process is typically more than 99% water and sand, and less than 1% of highly diluted chemical additives; lists of the chemical additives most typically used in fracturing fluids are available to the public via internet websites and in other publications sponsored by industry trade associations and through state agencies in those states that require the reporting of the components of fracturing fluids. While the majority of the sand remains underground to hold open the fractures, a significant percentage of the water and chemical additives flow back and are then either reused or safely disposed of at sites that are approved and permitted by the appropriate regulatory authorities. EOG regularly conducts audits of these disposal facilities to monitor compliance with all applicable regulations.

Currently, the regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements (such as the reporting and public disclosure of the chemical additives used in the fracturing process) and in additional operating restrictions. In addition to these federal proposals, some states and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; disclosure of the chemical additives used in hydraulic fracturing operations; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Such federal, state and local permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

EOG is unable to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing, but the direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Environmental Regulation - Canada. All phases of the oil and 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 into 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.

Spills and releases from EOG's properties may have resulted, or may result, in soil and groundwater contamination in certain locations. 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.

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, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such 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, financial condition and results of operations.

Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. The Canadian federal government has indicated an intention to work with the United States to regulate industrial emissions of GHG and air pollutants from a broad range of industrial sectors, with a stated goal to reduce Canada's total GHG emissions by 17% from 2005 levels by 2020. In addition, regulation of GHG emissions in Canada takes 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. British Columbia regulates GHG emissions under the Greenhouse Gas Reduction Targets Act, the Greenhouse Gas Reduction (Cap and Trade) Act, which imposes hard caps on GHG emissions, and the Reporting Regulation, which requires mandatory reporting of GHG emissions. In addition, the Government of Manitoba is currently considering the creation of a cap-and-trade system to reduce GHG emissions in Manitoba. Canada was an original signatory to the United Nations Framework Convention on Climate Change (also known as the Kyoto Protocol), but Canada recently announced its withdrawal from the Kyoto Protocol, effective December 2012.

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 of compliance within that country. EOG currently has operations in Trinidad, the United Kingdom, China and Argentina.

EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations. EOG will continue to review the risks to its business and operations associated with all environmental matters, including climate change and hydraulic fracturing. In addition, EOG will continue to monitor and assess any new policies, legislation, regulations and treaties in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Other Matters

Energy Prices. EOG is a crude oil and natural gas producer and is impacted by changes in prices for crude oil and condensate, natural gas liquids and natural gas. Crude oil and condensate and natural gas liquids production comprised a larger portion of EOG's production mix in 2011 than in prior years and is expected to comprise an even larger portion in 2012. Average crude oil and condensate prices received by EOG for production in the United States and Canada increased by 24% in 2011, increased by 37% in 2010 and decreased by 38% in 2009, each as compared to the immediately preceding year. The average New York Mercantile Exchange (NYMEX) crude oil strip price for 2012 has increased approximately 7% subsequent to December 31, 2011. Average United States and Canada wellhead natural gas prices have fluctuated, at times rather dramatically, during the last three years. These fluctuations resulted in an 8% decrease in the average wellhead natural gas price received by EOG for production in the United States and Canada in 2011, an increase of 13% in 2010 and a decrease of 54% in 2009, each as compared to the immediately preceding year. The average NYMEX natural gas strip price for 2012 has decreased by approximately 6% since December 31, 2011. Due to the many uncertainties associated with the world political environment, the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors, EOG is unable to predict what changes may occur in crude oil and condensate, natural gas liquids and natural gas prices in the future. For additional discussion regarding changes in crude oil and natural gas prices and the risks that such changes may present to EOG, see ITEM 1A. Risk Factors.

Including the impact of EOG's 2012 crude oil derivative contracts and based on EOG's tax position, EOG's price sensitivity in 2012 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $31 million for net income and $46 million for cash flows from operating activities. Including the impact of EOG's 2012 natural gas derivative contracts and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2012 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $11 million for net income and $16 million for cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts at February 24, 2012, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. For a summary of EOG's financial commodity derivative contracts at December 31, 2011, 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 crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily collar, price swap, option and basis swap contracts, as a means to manage this price risk. See Note 11 to Consolidated Financial Statements. 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 the provisions of the Derivatives and Hedging Topic of the Accounting Standards Codification, 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 at February 24, 2012, see ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. For a summary of EOG's financial commodity derivative contracts at December 31, 2011, see Note 11 to Consolidated Financial Statements.

All of EOG's crude oil and natural gas activities are subject to the risks normally incident to the exploration for, and development and production of, crude oil and natural gas, including blowouts, rig and well explosions, cratering, fires and loss of well control, each of which could result in damage to life, property and/or the environment. EOG's onshore and offshore operations are also subject to usual customary perils, including hurricanes and other adverse weather conditions. Moreover, EOG's activities are subject to governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events could reduce revenues and increase costs to EOG to the extent not covered by insurance.

Insurance is maintained by EOG against some, but not all, of these risks in accordance with what EOG believes are customary industry practices and in amounts and at costs that EOG believes to be prudent and commercially practicable. Specifically, EOG maintains commercial general liability and excess liability coverage provided by third-party insurers for bodily injury or death claims resulting from an incident involving EOG's onshore or offshore operations (subject to policy terms and conditions). Moreover, in the event an incident with respect to EOG's onshore or offshore operations results in negative environmental effects, EOG maintains operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that EOG may incur from such an incident, including obligations, expenses or claims in respect of seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be EOG's primary coverage, with the commercial general liability and excess liability coverage referenced above also providing certain coverage to EOG. All of EOG's onshore and offshore drilling activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. The indemnification and other risk allocation provisions included in such contracts are negotiated on a contract-by-contract basis and are each based on the particular circumstances of the services being provided and the anticipated operations.

In addition to the above-described risks, EOG's operations outside the United States are subject to certain risks, including the risk of increases in taxes and governmental royalties, changes in laws and policies governing the operations of foreign-based companies, expropriation of assets, unilateral or forced renegotiation or modification of existing contracts with governmental entities, currency restrictions and exchange rate fluctuations. 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 natural gas 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 a discussion of 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 24, 2012) are as follows:

Name	Age	Position
Mark G. Papa	65	Chairman of the Board and Chief Executive Officer; Director
William R. Thomas	59	President
Gary L. Thomas	62	Chief Operating Officer
Fredrick J. Plaeger, II	58	Senior Vice President and General Counsel
Timothy K. Driggers	50	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 also a director of Oil States International, Inc., an oilfield service company, where he serves on the Compensation and Nominating and Corporate Governance committees. From July 2003 to April 2005, Mr. Papa served as a director of the general partner of Magellan Midstream Partners LP, a pipeline and terminal company, where he served as Chairman of the Compensation Committee and as a member of the Audit and Conflicts Committees. Mr. Papa is EOG's principal executive officer.

William R. Thomas was elected President in September 2011. He was elected Senior Vice President and General Manager of EOG's Fort Worth, Texas office in June 2004, Executive Vice President and General Manager of EOG's Fort Worth, Texas office in February 2007, Senior Executive Vice President, Exploitation in February 2011, and served as Senior Executive Vice President, Exploration from July 2011 to September 2011. Mr. Thomas joined a predecessor of EOG in January 1979.

Gary L. Thomas was elected Chief Operating Officer in September 2011. He was elected Executive Vice President, North America Operations in May 1998, Executive Vice President, Operations in May 2002, and served as Senior Executive Vice President, Operations from February 2007 to September 2011. He also previously served as Senior Vice President and General Manager of EOG's Midland, Texas office. Mr. Thomas joined a predecessor of EOG in July 1978.

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 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 herein, including the consolidated financial statements and the related notes. Unless the context requires otherwise, "we," "us" and "our" refer to EOG Resources, Inc. and its subsidiaries.

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

Prices for crude oil and natural gas (including prices for natural gas liquids and condensate) fluctuate widely. Among the factors that can or could cause these price fluctuations are:

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

Our cash flow and results of operations depend to a great extent on the prevailing prices for crude oil and natural gas. Prolonged or substantial declines in crude oil and/or natural gas 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 crude oil and natural gas prices in the future such that the expected future cash flow from our crude oil and natural gas properties falls below the net book value of our properties, we may be required to write down the value of our crude oil and natural gas 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 crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). 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, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, 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, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental laws and regulations relating to air emissions, waste disposal and hydraulic fracturing, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;
- 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, rail cars, crude oil hauling trucks and qualified drivers and related facilities and equipment to gather, process, compress, transport and market crude oil, natural gas and related commodities; and
- costs of, or shortages or delays in the availability of, drilling rigs, pressure pumping equipment and supplies, tubular materials, water resources, sand, disposal facilities, qualified personnel and other necessary equipment, supplies and services.

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 in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

Our crude oil and natural gas operations involve many risks and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our onshore and offshore operations are subject to all of the risks associated with exploring and drilling for, and producing, gathering, processing and transporting, crude oil and natural gas, including the risks of:

- well blowouts and cratering;
- loss of well control;
- crude oil spills, natural gas leaks and pipeline ruptures;
- pipe failures and casing collapses;
- uncontrollable flows of crude oil, natural gas, formation water or drilling fluids;
- releases of chemicals or other hazardous substances;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and other natural disasters;
- fires and explosions;

- terrorism or vandalism;
- formations with abnormal pressures; and
- malfunctions of gathering, processing and other equipment.

If any of these events occur, we could incur losses and liabilities as a result of:

- injury or loss of life;
- damage to, or destruction of, property, equipment and crude oil and natural gas reservoirs;
- pollution or other environmental damage;
- regulatory investigations and penalties as well as clean-up and remediation responsibilities and costs;
- suspension or interruption of our operations, including due to injunction; and
- repairs necessary to resume operations.

We maintain insurance against many, but not all, such losses and liabilities 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 losses or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage, would reduce the funds available to us for our onshore and offshore exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

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

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of, 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 crude oil and natural gas properties generally declines as reserves are produced. Except to the extent that we conduct successful exploration, exploitation and development activities, acquire additional properties containing reserves or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our reserves will decline as they are produced. Maintaining our production of crude oil and natural gas at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves, which could in turn impact our future cash flow and results of operations.

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 by federal, state and local governments and regulatory agencies, both domestically and 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 oil and gas 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, results of operations and financial condition.

Specifically, as an owner or lessee and operator of crude oil and natural gas 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. Moreover, we are subject to the United States (U.S.) Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions. Changes in, or additions to, these regulations could lead to increased operating and compliance costs and, in turn, materially and adversely affect our business, results of operations and financial condition.

Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, we are also aware of legislation proposed by U.S. lawmakers and by the Canadian federal and provincial governments to reduce GHG emissions.

Additionally, there have been various proposals to regulate hydraulic fracturing at the federal level. Most onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. Currently, the regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements (such as the reporting and public disclosure of the chemical additives used in the fracturing process) and in additional operating restrictions. In addition to the possible federal regulation of hydraulic fracturing, some states and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells, testing of nearby water wells, restrictions on the access to and usage of water, disclosure of the chemical additives used in hydraulic fracturing operations and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Such federal and state permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. Accordingly, our production of crude oil and natural gas could be materially and adversely affected. For additional discussion regarding climate change and hydraulic fracturing, see Environmental Regulation – United States and Environmental Regulation – Canada under ITEM 1. Business – Regulation.

We will continue to monitor and assess any proposed or new policies, legislation, regulations and treaties in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary. We are unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations and financial condition. For related discussion, see the risk factor below regarding the provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act with respect to regulation of derivatives transactions and entities (such as EOG) that participate in such transactions.

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

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, 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 crude oil or natural gas 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 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. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

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

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us 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 crude oil and natural gas reserves (as discussed further below), 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.

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, exploration, development and production of crude oil and natural gas reserves. We intend to finance our capital expenditures primarily through our cash flow from operations, commercial paper borrowings, sales of assets and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facility and public and private equity and debt offerings.

Lower crude oil and natural gas 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 weakness and volatility in domestic and global financial markets and economic conditions in recent years 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 or other borrowings. Moreover, a reduction in our cash flow (for example, as a result of lower crude oil and natural gas prices) and the corresponding adverse effect on our financial condition and results of operations may increase the interest rates that lenders and commercial paper investors require us to pay. In addition, a substantial increase 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 crude oil, natural gas 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 weakened in recent years and remain relatively weak. In addition, there continues to be weakness and volatility in domestic and global financial markets relating to the credit crisis in recent years, 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 crude oil, natural gas 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, government-affiliated 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 contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce and market crude oil and natural gas. 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 certain respects, such as in bidding for drilling rights or in acquiring necessary services, equipment, supplies and personnel. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition, to a lesser extent, from competing energy sources, such as 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 liquids and natural gas reserves and future net cash flows from such reserves is a complex, inexact 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 liquids and natural gas 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, many of which factors are or may be beyond our control. Our actual reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance, including any significant revisions to our existing reserve estimates, could materially and adversely affect our business, financial condition and results of operations and, in turn, the trading price of our common stock. For related discussion, see ITEM 2. Properties – Oil and Gas Exploration and Production – Properties and Reserves.

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

Demand for crude oil and natural gas 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, exploitation and development activities and equipment can be adversely affected by extreme weather conditions, such as winter storms, flooding and 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. Such 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 services. Such extreme weather conditions and changes in weather patterns may materially and adversely affect our business and, in turn, our financial condition and results of operations.

Our hedging activities may prevent us from benefiting fully from increases in crude oil and natural gas 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 crude oil and natural gas 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 crude oil and natural gas 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.

Recent federal legislation and related regulations regarding derivatives transactions could have a material and adverse impact on our hedging activities.

As discussed in the risk factor immediately above, we use derivative instruments to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flow. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which, among other matters, establishes a comprehensive framework for the regulation of derivatives, or "swaps." The U.S. Securities and Exchange Commission, which has jurisdiction over security-based swaps, and the Commodity Futures Trading Commission, which has jurisdiction over swaps, are in the process of adopting regulations to implement this new regulatory regime. Once implemented, entities such as EOG that enter into swaps will be subject to, among other provisions, swap recordkeeping and reporting requirements; position limits for certain referenced futures contracts in the major energy markets and economically equivalent futures, options and swaps; and, subject to certain exceptions which may be applicable to EOG, swap clearing, trade execution and margin requirements (i.e., collateral posting requirements). Our swap counterparties could be subject to even greater regulatory oversight and may be subject to regulated capital requirements.

The applicability of such provisions (and the availability of certain exemptions) to EOG, our hedging activities and our hedging counterparties is currently uncertain, as many of the implementing regulations have not been finalized. However, the legislation and related regulations could significantly increase our cost of compliance, increase the cost and alter the terms of derivatives transactions, and adversely impact the number and creditworthiness of available swap counterparties. All of this could impact our available liquidity, require us to divert funds away from our exploration, development and production activities (e.g., in order to satisfy margin/collateral posting requirements) and reduce our ability to hedge and otherwise manage our financial and commercial risks related to crude oil and natural gas price fluctuations. If we reduce our use of derivatives as a result of the legislation and related regulations, our results of operations may become more volatile and our cash flow may be less predictable, which could materially and adversely affect our ability to plan for and fund our capital expenditure requirements. Any of the foregoing consequences could have a material and adverse effect on our business, financial condition and results of operations.

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

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

- increases in taxes and governmental royalties;
- changes in laws and policies governing operations of foreign-based companies;
- loss of revenue, equipment and property as a result of expropriation, acts of terrorism, war, civil unrest and other political risks;
- unilateral or forced renegotiation, modification or nullification of existing 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; 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.

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, 2011, approximately 5% of our net operating 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 and the threat of such actions could materially and adversely affect us in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in crude oil and natural gas prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

ITEM 1B. ***Unresolved Staff Comments***

Not applicable.

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 crude oil and condensate, natural gas liquids and natural gas, as well as discussion of EOG's proved undeveloped reserves, the qualifications of the preparers of EOG's reserve estimates, EOG's independent petroleum consultants and EOG's processes and controls with respect to its reserve estimates, 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 crude oil and condensate, natural gas liquids and natural gas 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 crude oil and natural gas properties declines as reserves are produced. 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. The volumes to be 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, 2011. 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	1,742,667	1,303,030	4,950,407	3,572,980	6,693,074	4,876,010
Canada	1,228,360	1,021,507	804,486	748,509	2,032,846	1,770,016
Trinidad	75,717	65,719	48,520	38,816	124,237	104,535
United Kingdom	8,797	2,570	118,333	94,730	127,130	97,300
China	130,546	130,546	-	-	130,546	130,546
Total	3,186,087	2,523,372	5,921,746	4,455,035	9,107,833	6,978,407

Most of our oil and gas leases, particularly in the United States, are subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. Company-wide, approximately 1.02 million net acres will expire in 2012, 0.9 million net acres will expire in 2013 and 0.6 million net acres will expire in 2014 if production is not established or we take no other action to extend the terms of the leases or concessions. In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Producing Well Summary. EOG operated 15,772 gross and 13,977 net producing crude oil and natural gas wells at December 31, 2011. Gross crude oil and natural gas wells include 1,577 wells with multiple completions.

	Crude Oil		**Natural Gas**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	2,905	2,076	7,096	5,830	10,001	7,906
Canada	698	587	6,888	6,192	7,586	6,779
Trinidad	13	10	29	25	42	35
United Kingdom	-	-	1	-	1	-
China	-	-	25	24	25	24
Total	3,616	2,673	14,039	12,071	17,655	14,744

Drilling and Acquisition Activities. During the years ended December 31, 2011, 2010 and 2009, EOG expended \$6.6 billion, \$5.5 billion and \$3.9 billion, respectively, for exploratory and development drilling and acquisition of leases and producing properties, including asset retirement obligations of \$133 million, \$72 million and \$84 million, respectively. The following tables set forth the results of the gross crude oil and natural gas wells drilled and completed for the years ended December 31, 2011, 2010 and 2009:

	Gross Development Wells Completed				**Gross Exploratory Wells Completed**			
	Crude Oil	**Natural Gas**	**Dry Hole**	**Total**	**Crude Oil**	**Natural Gas**	**Dry Hole**	**Total**
2011								
United States	851	203	24	1,078	11	4	2	17
Canada	105	9	-	114	2	-	-	2
Trinidad	-	7	-	7	-	-	-	-
China	-	-	-	-	-	1	2	3
Total	956	219	24	1,199	13	5	4	22
2010								
United States	589	448	32	1,069	19	8	10	37
Canada	128	25	-	153	1	-	-	1
Trinidad	-	-	-	-	-	1	-	1
United Kingdom	-	-	-	-	-	-	3	3
China	-	-	-	-	-	2	-	2
Total	717	473	32	1,222	20	11	13	44
2009								
United States	195	407	26	628	22	23	7	52
Canada	38	60	-	98	3	-	-	3
United Kingdom	-	-	-	-	1	-	1	2
Total	233	467	26	726	26	23	8	57

The following tables set forth the results of the net crude oil and natural gas wells drilled and completed for the years ended December 31, 2011, 2010 and 2009:

	Net Development Wells Completed				**Net Exploratory Wells Completed**			
	Crude Oil	**Natural Gas**	**Dry Hole**	**Total**	**Crude Oil**	**Natural Gas**	**Dry Hole**	**Total**
2011								
United States	687	138	18	843	9	3	2	14
Canada	95	4	-	99	2	-	-	2
Trinidad	-	7	-	7	-	-	-	-
China	-	-	-	-	-	1	2	3
Total	782	149	18	949	11	4	4	19
2010								
United States	459	374	29	862	16	7	10	33
Canada	128	25	-	153	1	-	-	1
Trinidad	-	-	-	-	-	1	-	1
United Kingdom	-	-	-	-	-	-	3	3
China	-	-	-	-	-	2	-	2
Total	587	399	29	1,015	17	10	13	40
2009								
United States	143	351	22	516	14	17	6	37
Canada	38	48	-	86	3	-	-	3
United Kingdom	-	-	-	-	1	-	1	2
Total	181	399	22	602	18	17	7	42

EOG participated in the drilling of wells that were in progress at the end of the period as set out in the table below for the years ended December 31, 2011, 2010 and 2009:

	Wells in Progress at End of Period					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
United States	359	282	243	205	277	239
Canada	-	-	1	1	5	4
Trinidad	-	-	-	-	1	1
United Kingdom	3	2	3	2	1	-
China	1	1	4	4	4	4
Total	363	285	251	212	288	248

EOG acquired wells, which includes the acquisition of additional interests in certain wells in which EOG previously owned an interest, as set out in the tables below for the years ended December 31, 2011, 2010 and 2009:

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2011						
United States	8	-	8	4	-	4
Canada	-	5	5	-	5	5
Total	8	5	13	4	5	9
2010						
Canada	1	-	1	1	-	1
Total	1	-	1	1	-	1
2009						
United States	133	579	712	126	243	369
Canada	-	2	2	-	1	1
Total	133	581	714	126	244	370

All of EOG's drilling activities are conducted on a contractual basis with independent drilling contractors. EOG does not own drilling equipment. EOG's other property, plant and equipment primarily includes gathering, transportation and processing infrastructure assets, along with sand mine and sand processing assets which support EOG's exploration and production activities.

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. *Mine Safety Disclosures*

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

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. The quarterly cash dividend on EOG's common stock has historically been declared in the quarter immediately preceding the quarter of payment and paid on January 31, April 30, July 31 and October 31 of each year (or, if such day is not a business day, the immediately preceding business day).

	Price Range		
	High	Low	Dividend Declared
2011			
First Quarter	$ 121.44	$ 90.84	$ 0.160
Second Quarter	119.82	96.62	0.160
Third Quarter	107.88	69.55	0.160
Fourth Quarter	106.20	66.81	0.160
2010			
First Quarter	$ 100.44	$ 86.78	$ 0.155
Second Quarter	114.95	93.28	0.155
Third Quarter	108.47	85.42	0.155
Fourth Quarter	102.06	86.00	0.155

On February 16, 2012, EOG's Board of Directors (Board) increased the quarterly cash dividend on the common stock from the current $0.16 per share to $0.17 per share, effective beginning with the dividend to be paid on April 30, 2012 to stockholders of record as of April 16, 2012.

As of February 15, 2012, there were approximately 1,850 record holders and approximately 251,000 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, 2011 - October 31, 2011	2,196	$79.66	-	6,386,200
November 1, 2011 - November 30, 2011	8,756	98.52	-	6,386,200
December 1, 2011 - December 31, 2011	30,030	98.22	-	6,386,200
Total	40,982	97.29		

(1) The 40,982 total shares for the quarter ended December 31, 2011 and the 267,430 shares for the full year 2011 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 repurchase 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 2011, EOG did not repurchase any shares under the Board-authorized repurchase program.

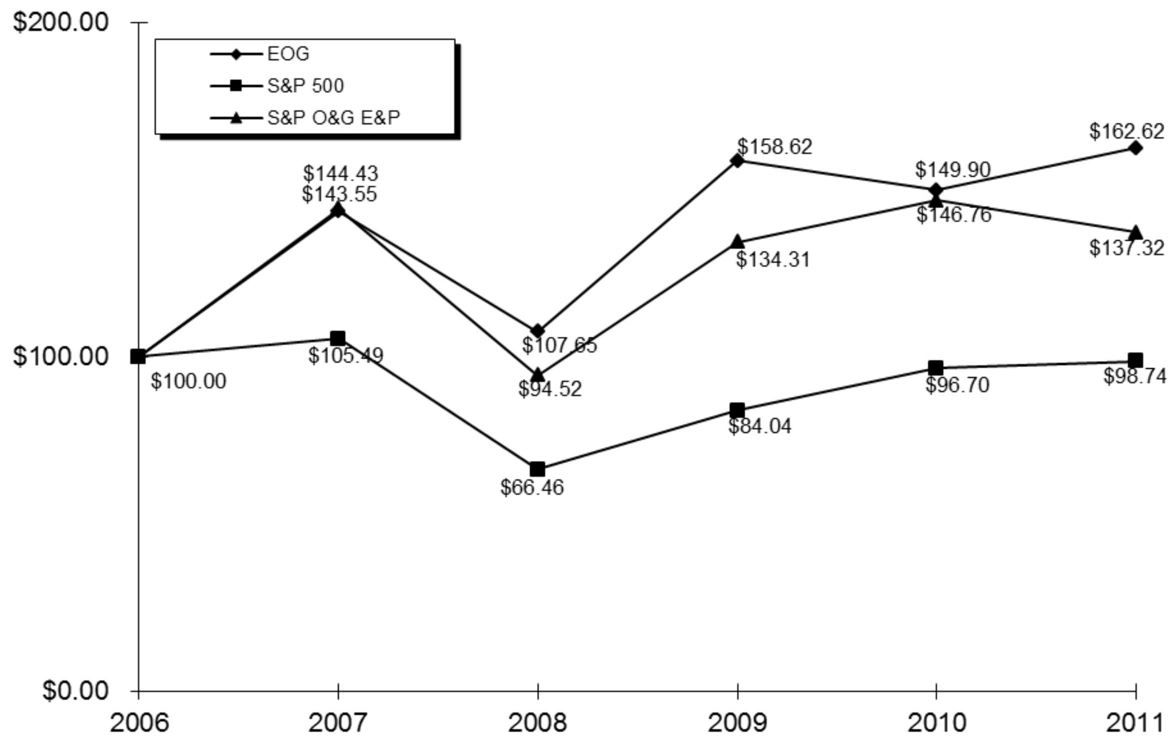
Comparative Stock Performance

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, 2006 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, 2011)



*Cumulative total return assumes reinvestment of dividends.

	2006	2007	2008	2009	2010	2011
EOG	$100.00	$143.55	$107.65	$158.62	$149.90	$162.62
S&P 500	$100.00	$105.49	$ 66.46	$ 84.04	$ 96.70	$ 98.74
S&P O&G E&P	$100.00	$144.43	$ 94.52	$134.31	$146.76	$137.32

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

Year Ended December 31	**2011**	**2010**	**2009**	**2008**	**2007**
Statement of Income Data:					
Net Operating Revenues	$ 10,126,115	$ 6,099,896	$ 4,786,959	$ 7,127,143	$ 4,239,303
Operating Income	$ 2,113,309	$ 523,319	$ 970,841	$ 3,767,185	$ 1,648,396
Net Income	$ 1,091,123	$ 160,654	$ 546,627	$ 2,436,919	$ 1,089,918
Preferred Stock Dividends	-	-	-	443	6,663
Net Income Available to Common Stockholders	$ 1,091,123	$ 160,654	$ 546,627	$ 2,436,476	$ 1,083,255
Net Income Per Share Available to Common Stockholders					
Basic	$ 4.15	$ 0.64	$ 2.20	$ 9.88	$ 4.45
Diluted	$ 4.10	$ 0.63	$ 2.17	$ 9.72	$ 4.37
Dividends Per Common Share	$ 0.64	$ 0.62	$ 0.58	$ 0.51	$ 0.36
Average Number of Common Shares					
Basic	262,735	250,876	248,996	246,662	243,469
Diluted	266,268	254,500	251,884	250,542	247,637

At December 31	**2011**	**2010**	**2009**	**2008**	**2007**
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 21,288,824	$ 18,680,900	$ 16,139,225	$ 13,657,302	$ 10,429,254
Total Assets	24,838,797	21,624,233	18,118,667	15,951,226	12,088,907
Long-Term Debt and Current Portion of Long-Term Debt	5,009,166	5,223,341	2,797,000	1,897,000	1,185,000
Total Stockholders' Equity	12,640,904	10,231,632	9,998,042	9,014,497	6,990,094

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) crude oil and natural gas companies in the United States with proved reserves in the United States, Canada, Trinidad, the United Kingdom and China. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. 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.

Net income for 2011 totaled $1,091 million as compared to $161 million for 2010. At December 31, 2011, EOG's total estimated net proved reserves were 2,054 million barrels of oil equivalent (MMBoe), an increase of 104 MMBoe from December 31, 2010. During 2011, net proved crude oil and condensate and natural gas liquids reserves increased by 207 million barrels (MMBbl) and net proved natural gas reserves decreased by 619 billion cubic feet (Bcf) or 103 MMBoe.

Operations

Several important developments have occurred since January 1, 2011.

United States and Canada. EOG's efforts to identify plays with large 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 crude oil and natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise gained from its natural gas resource plays to unconventional crude oil and liquids-rich reservoirs. In 2011, EOG focused its efforts on developing its existing North American crude oil and condensate and liquids-rich acreage. In addition, EOG continues to evaluate certain potential liquids-rich exploration and development prospects. During 2011, crude oil and condensate and natural gas liquids production accounted for approximately 37% of total company production as compared to 27% during 2010. North American liquids production accounted for approximately 42% of total North American production during 2011 as compared to 31% in 2010. This liquids growth reflects production from EOG's 572,000 net acre position in the oil window of the Eagle Ford Shale play near San Antonio, Texas, and increasing amounts of crude oil and condensate and natural gas liquids production in the Fort Worth Basin Barnett Shale area. In 2011, EOG's net Eagle Ford Shale production averaged 34.1 thousand barrels per day (MBbld) of crude oil and condensate and natural gas liquids as compared to 4.3 MBbld in 2010. Based on current trends, EOG expects its 2012 crude oil and condensate and natural gas liquids production to continue to increase both in total and as a percentage of total company production as compared to 2011. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada. EOG delivers its crude oil to various markets in the United States, including sales points on the Gulf Coast. Most recently, with increases in crude oil production from the Eagle Ford Shale play, EOG has increased sales to the Gulf Coast and is receiving pricing for those sales based on the Light Louisiana Sweet price. In order to create further market diversification for its growing crude oil production, EOG is expanding its crude-by-rail system to have the capability to increase deliveries of crude oil to St. James, Louisiana, beginning in the second quarter of 2012. In addition, to further reduce well completion costs, EOG began using sand from its Wisconsin sand mine and sand processing facilities in late 2011.

In March 2011, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), purchased an additional 24.5% interest in the proposed Pacific Trail Pipelines (PTP) for $25.2 million. The PTP is intended to link western Canada's natural gas producing regions to the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal). A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally, in March 2011, EOGRC and an affiliate of Apache Corporation (Apache), through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage. In the first quarter of 2011, EOGRC and Apache awarded a front-end engineering and design contract to a global engineering company with the final report expected in the second half of 2012. In October 2011, the Canadian National Energy Board granted a 20-year export license to ship LNG from the Kitimat LNG Terminal to international markets.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium (SECC) Block, Modified U(a) Block and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing natural gas and crude oil and condensate. In Block 4(a), EOG drilled and completed six development wells in the Toucan Field and one in the EMZ Area in 2011. Production from all seven wells began in February 2012 to supply natural gas under a contract with the Natural Gas Company of Trinidad and Tobago. EOG sourced the natural gas for this contract from its existing fields until the Toucan Field began producing.

In 2006, EOG Resources United Kingdom Limited (EOGUK) participated in the drilling and successful testing of the Columbus prospect in the Central North Sea Block 23/16f. EOG has a 25% non-operating interest in this block. A successful Columbus prospect appraisal well was drilled during the third quarter of 2007. The field operator submitted a revised field development plan to the U.K. Department of Energy and Climate Change (DECC) during the second quarter of 2011 and anticipates receiving approval of this plan in the first half of 2012. The operator and partners are continuing to negotiate processing and transportation terms with export infrastructure owners.

In 2009, EOGUK drilled a successful exploratory well in its East Irish Sea Blocks 110/7b and 110/12a. Well 110/12-6, in which EOGUK has a 100% working interest, was an oil discovery and was designated the Conwy field. In 2010, EOGUK added an adjoining field in its East Irish Sea block, designated Corfe, to its overall development plans. During 2011, offshore facilities fabrication began, line pipe was fabricated and all principal facilities and drilling contracts were signed. Field development plans for the Conwy and Corfe fields were submitted to the DECC during the first quarter of 2011. Regulatory approval of both plans is expected during the first quarter of 2012. Installation of facilities, pipelines and drilling of development wells are planned for 2012 with initial production expected during the first quarter of 2013. The licenses for the East Irish Sea blocks were awarded to EOGUK 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, China. In October 2008, EOG obtained the rights to shallower zones on the acreage acquired. During the first quarter of 2011, EOG completed one horizontal well.

During 2011, EOG signed two exploration contracts and one farm-in agreement covering approximately 100,000 net acres in the Neuquén Basin in Neuquén Province, Argentina. During the third quarter of 2011, EOG performed exploration activity on a portion of this acreage in preparation for drilling a well targeting the Vaca Muerta oil shale in the Aguada del Chivato Block. EOG began drilling this well in January 2012. In the first quarter of 2012, EOG plans to participate in the drilling of a second well in the Bajo de Toro Block targeting the Vaca Muerta oil shale.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas 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. EOG's debt-to-total capitalization ratio was 28% and 34% at December 31, 2011 and 2010, respectively. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

During 2011, EOG funded $7.1 billion in exploration and development and other property, plant and equipment expenditures (excluding asset retirement obligations), repaid $220 million in long-term debt, paid $167 million in dividends to common stockholders and purchased $24 million of treasury stock in connection with stock compensation plans, primarily by utilizing cash provided from its operating activities, proceeds of $1,388 million from the sale of common stock and proceeds of $1,433 million from the sale of certain North American assets and the sale of a portion of EOG's interest in the Kitimat LNG Terminal and PTP.

On October 11, 2011, EOG entered into a $2.0 billion senior unsecured Revolving Credit Agreement (2011 Facility) with domestic and foreign lenders. The 2011 Facility replaced EOG's two $1.0 billion senior unsecured credit facilities which were cancelled by EOG upon the closing of the 2011 Facility. Unamortized fees relating to the cancelled facilities totaling $5.7 million were written off in the fourth quarter of 2011. The 2011 Facility has a scheduled maturity date of October 11, 2016 and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods.

On March 7, 2011, EOG completed the sale of 13,570,000 shares of EOG common stock, par value $0.01 per share (Common Stock), at the public offering price of $105.50 per share. Net proceeds from the sale of the Common Stock were approximately $1,388 million after deducting the underwriting discount and offering expenses. Proceeds from the sale were used for general corporate purposes, including funding capital expenditures.

Total anticipated 2012 capital expenditures are expected to range from $7.4 to $7.6 billion, excluding acquisitions. The majority of 2012 expenditures will be focused on United States and Canada crude oil and liquids-rich gas drilling activity and, to a much lesser extent, natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays to hold acreage. EOG expects capital expenditures to be greater than cash flow from operating activities for 2012. EOG's business plan includes selling certain non-core assets in 2012 to partially cover the anticipated shortfall. However, EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under the 2011 Facility and equity and debt offerings.

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.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2011 should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning with page F-1.

Net Operating Revenues

During 2011, net operating revenues increased $4,026 million, or 66%, to $10,126 million from $6,100 million in 2010. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, natural gas liquids and natural gas, in 2011 increased $1,977 million, or 41%, to $6,858 million from $4,881 million in 2010. During 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $626 million compared to net gains of $62 million in 2010. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as gathering fees associated with gathering third-party natural gas, increased $1,206 million, or 133%, during 2011, to $2,116 million from $910 million in 2010. Gains on asset dispositions, net, totaled $493 million and $224 million in 2011 and 2010, respectively, primarily as a result of asset dispositions in the Rocky Mountain area and Texas in 2011 and in the Rocky Mountain area in 2010.

Wellhead volume and price statistics for the years ended December 31, 2011, 2010 and 2009 were as follows:

Year Ended December 31	**2011**	**2010**	**2009**
Crude Oil and Condensate Volumes (MBbld) [1]			
United States	102.0	63.2	47.9
Canada	7.9	6.7	4.1
Trinidad	3.4	4.7	3.1
Other International [2]	0.1	0.1	0.1
Total	**113.4**	**74.7**	**55.2**
Average Crude Oil and Condensate Prices ($/Bbl) [3]			
United States	$ 92.92	$ 74.88	$ 54.42
Canada	91.92	72.66	57.72
Trinidad	90.62	68.80	50.85
Other International [2]	100.11	73.11	53.07
Composite	**92.79**	**74.29**	**54.46**
Natural Gas Liquids Volumes (MBbld) [1]			
United States	41.5	29.5	22.5
Canada	0.9	0.9	1.1
Total	**42.4**	**30.4**	**23.6**
Average Natural Gas Liquids Prices ($/Bbl) [3]			
United States	$ 50.37	$ 41.68	$ 30.03
Canada	52.69	43.40	30.49
Composite	**50.41**	**41.73**	**30.05**
Natural Gas Volumes (MMcfd) [1]			
United States	1,113	1,133	1,134
Canada	132	200	224
Trinidad	344	341	273
Other International [2]	13	14	14
Total	**1,602**	**1,688**	**1,645**
Average Natural Gas Prices ($/Mcf) [3]			
United States	$ 3.92	$ 4.30	$ 3.72
Canada	3.71	3.91	3.85
Trinidad	3.53	2.65	1.73
Other International [2]	5.62	4.90	4.34
Composite	**3.83**	**3.93**	**3.42**
Crude Oil Equivalent Volumes (MBoed) [4]			
United States	329.1	281.5	259.4
Canada	30.7	40.9	42.6
Trinidad	60.7	61.5	48.5
Other International [2]	2.2	2.5	2.4
Total	**422.7**	**386.4**	**352.9**
Total MMBoe [4]	154.3	141.1	128.8

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Other International includes EOG's United Kingdom and China operations.
(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 11 to Consolidated Financial Statements).
(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, natural gas liquids and natural gas. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

2011 compared to 2010. Wellhead crude oil and condensate revenues in 2011 increased $1,839 million, or 92%, to $3,838 million from $1,999 million in 2010, due to an increase of 39 MBbld, or 52%, in wellhead crude oil and condensate deliveries ($1,074 million) and a higher composite average wellhead crude oil and condensate price ($765 million). The increase in deliveries primarily reflects increased production in Texas (35 MBbld) and Colorado (3 MBbld). Production increases in Texas were the result of increased production from the Eagle Ford Shale (26 MBbld) and Fort Worth Basin Barnett Combo (8 MBbld) plays. EOG's composite average wellhead crude oil and condensate price for 2011 increased 25% to $92.79 per barrel compared to $74.29 per barrel in 2010.

Natural gas liquids revenues in 2011 increased $317 million, or 69%, to $779 million from $462 million in 2010, due to an increase of 12 MBbld, or 39%, in natural gas liquids deliveries ($183 million) and a higher composite average price ($134 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale (6 MBbld), the Eagle Ford Shale (4 MBbld) and the Rocky Mountain area (3 MBbld). EOG's composite average natural gas liquids price in 2011 increased 21% to $50.41 per barrel compared to $41.73 per barrel in 2010.

Wellhead natural gas revenues in 2011 decreased $179 million, or 7%, to $2,241 million from $2,420 million in 2010. The decrease was due to reduced natural gas deliveries ($123 million) and a lower composite average wellhead natural gas price ($56 million). EOG's composite average wellhead natural gas price decreased 3% to $3.83 per Mcf in 2011 from $3.93 per Mcf in 2010.

Natural gas deliveries in 2011 decreased 86 MMcfd, or 5%, to 1,602 MMcfd from 1,688 MMcfd in 2010. The decrease was primarily due to lower production in Canada (68 MMcfd) and the United States (20 MMcfd). The decrease in Canada primarily reflects sales of certain shallow natural gas assets in 2010, partially offset by increased production from the Horn River Basin area. The decrease in the United States was primarily attributable to decreased production in the Rocky Mountain area (36 MMcfd), Louisiana (17 MMcfd), Mississippi (11 MMcfd), New Mexico (8 MMcfd) and Kansas (5 MMcfd), partially offset by increased production in Texas (38 MMcfd) and Pennsylvania (23 MMcfd).

During 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $626 million, which included net realized gains of $181 million. During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million.

Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as fees associated with gathering third-party natural gas. For the years ended December 31, 2011, 2010 and 2009, gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. The purchase and sale of third-party crude oil and natural gas are utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs of purchasing third-party crude oil and natural gas and the associated transportation costs.

During 2011, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs in 2011 increased $19 million to $44 million from $25 million in 2010, primarily as a result of increased crude oil marketing activities.

2010 compared to 2009. Wellhead crude oil and condensate revenues in 2010 increased $909 million, or 83%, to $1,999 million from $1,090 million in 2009, due to a higher composite average wellhead crude oil and condensate price ($533 million) and an increase of 20 MBbld, or 35%, in wellhead crude oil and condensate deliveries ($376 million). The increase in deliveries primarily reflects increased production in Texas (8 MBbld), North Dakota (7 MBbld), Canada (3 MBbld) and Trinidad (2 MBbld). Production increases in Texas were the result of increased production from the Fort Worth Basin Barnett Combo and the Eagle Ford plays. Production increases in North Dakota resulted from increased deliveries from the Bakken and Three Forks plays. EOG's composite average wellhead crude oil and condensate price for 2010 increased 36% to $74.29 per barrel compared to $54.46 per barrel in 2009.

Natural gas liquids revenues in 2010 increased $203 million, or 79%, to $462 million from $259 million in 2009, due to a higher composite average price ($129 million) and an increase of 7 MBbld, or 29%, in natural gas liquids deliveries ($74 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area. EOG's composite average natural gas liquids price in 2010 increased 39% to $41.73 per barrel compared to $30.05 per barrel in 2009.

Wellhead natural gas revenues in 2010 increased $369 million, or 18%, to $2,420 million from $2,051 million in 2009. The increase was due to a higher composite average wellhead natural gas price ($316 million) and increased natural gas deliveries ($53 million). EOG's composite average wellhead natural gas price increased 15% to $3.93 per Mcf in 2010 from $3.42 per Mcf in 2009.

Natural gas deliveries in 2010 increased 43 MMcfd, or 3%, to 1,688 MMcfd from 1,645 MMcfd in 2009. The increase was primarily due to higher production in Trinidad (68 MMcfd), partially offset by decreased production in Canada (24 MMcfd) and the United States (1 MMcfd). The increase in Trinidad was primarily attributable to deliveries under a take-or-pay contract, which began January 1, 2010. The decrease in the United States was primarily attributable to decreased production in the Rocky Mountain area (28 MMcfd), offshore Gulf of Mexico (9 MMcfd), New Mexico (6 MMcfd), Texas (5 MMcfd), Kansas (5 MMcfd) and Mississippi (4 MMcfd), partially offset by increased production in Louisiana (45 MMcfd) and Pennsylvania (11 MMcfd).

During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized gains of $1,278 million.

During 2010, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs in 2010 totaled $25 million compared to $10 million in 2009, primarily as a result of higher crude oil marketing margins.

Operating and Other Expenses

2011 compared to 2010. During 2011, operating expenses of $8,013 million were $2,436 million higher than the $5,577 million incurred in 2010. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2011 and 2010:

	2011	2010
Lease and Well	$ 6.11	$ 4.96
Transportation Costs	2.79	2.74
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties (1)	15.52	13.19
Other Property, Plant and Equipment	0.79	0.79
General and Administrative (G&A)	1.98	1.99
Net Interest Expense	1.36	0.92
Total (2)	**$ 28.55**	**$ 24.59**

(1) The 2010 amount excludes the reductions in the estimated fair value of the contingent consideration liability of $24 million, or $0.17 per Boe related to the acquisition of certain unproved acreage.

(2) Total excludes 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 2011 compared to 2010 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 costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are 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 and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time. In general, operating and maintenance costs for wells producing crude oil are higher than operating and maintenance costs for wells producing natural gas.

Lease and well expenses of $942 million in 2011 increased $244 million from $698 million in 2010 primarily due to higher operating and maintenance expenses in the United States ($188 million), increased lease and well administrative expenses in the United States ($33 million), increased workover expenditures in the United States ($11 million) and Canada ($4 million) and unfavorable changes in the Canadian exchange rate ($6 million), partially offset by lower operating and maintenance costs in Canada ($4 million).

Transportation costs represent costs 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, transportation fees and costs associated with crude-by-rail operations.

Transportation costs of $430 million in 2011 increased $45 million from $385 million in 2010 primarily due to increased transportation costs in the Eagle Ford Shale ($30 million), the Upper Gulf Coast area ($16 million) and the Fort Worth Basin Barnett Shale area ($9 million), partially offset by decreased transportation costs in Canada ($4 million), the Rocky Mountain area ($2 million) and the South Texas area ($2 million). The net increase in transportation costs primarily reflects increased volumes transported 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 consists of gathering and processing assets, compressors, crude-by-rail assets, sand mine and sand processing assets, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses in 2011 increased $574 million to $2,516 million from $1,942 million in 2010. DD&A expenses associated with oil and gas properties in 2011 were $563 million higher than in 2010 primarily due to higher unit rates as described above ($375 million), increased production in the United States ($249 million), a reduction during 2010 in the fair value of the contingent consideration liability ($24 million) and unfavorable changes in the Canadian exchange rate ($11 million), partially offset by a decrease in production in Canada ($77 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($306 million), Trinidad ($37 million) and Canada ($9 million).

DD&A expenses associated with other property, plant and equipment were $11 million higher in 2011 than in 2010 primarily due to gathering and processing assets being placed in service in the Eagle Ford Shale ($5 million) and the Rocky Mountain area ($3 million).

G&A expenses of $305 million in 2011 were $25 million higher than 2010 due primarily to higher employee-related costs.

Net interest expense of $210 million in 2011 increased $80 million from $130 million in 2010 primarily due to a higher average debt balance ($56 million), lower capitalized interest ($18 million) and the write-off of fees associated with revolving credit facilities cancelled in 2011 in connection with the establishment of the 2011 Facility ($6 million).

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

Gathering and processing costs increased $14 million to $81 million in 2011 compared to $67 million in 2010. The increase primarily reflects increased activities in the Fort Worth Basin Barnett Shale area ($10 million), the Eagle Ford Shale ($5 million) and Canada ($5 million), partially offset by decreased activities in the Upper Gulf Coast region ($5 million) and the Rocky Mountain area ($4 million).

Exploration costs of $172 million in 2011 decreased $15 million from $187 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the United States.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties and other property, plant and equipment. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. When circumstances indicate that a proved property 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 are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach as described in the Fair Value Measurement and Disclosures Topic of the Financial Accounting Standards Board's Accounting Standards Codification (ASC). For certain natural gas assets held for sale, EOG utilized accepted bids as the basis for determining fair value.

Impairments of $1,031 million in 2011 increased $288 million from $743 million in 2010 primarily due to increased impairments of proved properties and other property, plant and equipment in the United States. EOG recorded impairments of proved properties and other property, plant and equipment of $834 million and $526 million in 2011 and 2010, respectively. The 2011 amount includes impairments of $745 million related to certain North American natural gas assets as a result of declining commodity prices and accepted bids.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are generally determined based on wellhead revenues and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

Taxes other than income in 2011 increased $94 million to $411 million (6% of wellhead revenues) from $317 million (6.5% of wellhead revenues) in 2010. The increase in taxes other than income was primarily due to increased severance/production taxes primarily as a result of increased wellhead revenues in the United States ($101 million) and a decrease in credits available to EOG in 2011 for Texas high cost gas severance tax rate reductions as a result of fewer wells qualifying for such credit ($8 million), partially offset by lower ad valorem/property taxes in the United States ($9 million) and Canada ($4 million) and decreased severance/production taxes in Trinidad ($4 million).

Other income, net was $7 million in 2011 compared to $14 million in 2010. The decrease of $7 million was primarily due to operating losses on EOG's investment in the PTP ($5 million) and an increase in foreign currency transaction losses ($5 million), partially offset by higher equity income from ammonia plants in Trinidad ($3 million).

Income tax provision of $819 million in 2011 increased $572 million from $247 million in 2010 due primarily to greater pretax income. The net effective tax rate for 2011 decreased to 43% from 61% in 2010. The effective tax rate for 2011 exceeded the United States statutory tax rate (35%) due mostly to foreign earnings in Trinidad (55% statutory tax rate) combined with losses in Canada (27% statutory tax rate).

2010 compared to 2009. During 2010, operating expenses of $5,577 million were $1,761 million higher than the $3,816 million incurred in 2009. The following table presents the costs per Boe for the years ended December 31, 2010 and 2009:

		2010		2009
Lease and Well	$	4.96	$	4.50
Transportation Costs		2.74		2.20
DD&A -				
Oil and Gas Properties (1)		13.19		11.29
Other Property, Plant and Equipment		0.79		0.74
G&A		1.99		1.93
Net Interest Expense		0.92		0.78
Total (2)	**$**	**24.59**	**$**	**21.44**

(1) The 2010 amount excludes the reductions in the estimated fair value of the contingent consideration liability of $24 million, or $0.17 per Boe related to the acquisition of certain unproved acreage.

(2) Total excludes 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 2010 compared to 2009 are set forth below.

Lease and well expenses of $698 million in 2010 increased $119 million from $579 million in 2009 primarily due to higher operating and maintenance expenses in the United States ($67 million) and Canada ($6 million), increased lease and well administrative expenses in the United States ($27 million), primarily due to higher costs associated with increased crude oil activities, unfavorable changes in the Canadian exchange rate ($14 million) and increased workover expenditures in the United States ($3 million) and Canada ($2 million).

Transportation costs of $385 million in 2010 increased $102 million from $283 million in 2009 primarily due to increased transportation costs in the Rocky Mountain area ($46 million), the Upper Gulf Coast area ($29 million) and the Fort Worth Basin Barnett Shale area ($29 million). These increases reflect costs associated with marketing arrangements to transport production to downstream markets. The increased transportation costs in the Rocky Mountain area also include costs associated with EOG's crude-by-rail operations, which began transporting crude oil from Stanley, North Dakota, to Cushing, Oklahoma, at the end of December 2009.

DD&A expenses in 2010 increased $393 million to $1,942 million from $1,549 million in 2009. DD&A expenses associated with oil and gas properties in 2010 were $378 million higher than in 2009 primarily due to higher unit rates described below and as a result of increased production in the United States ($97 million), Trinidad ($12 million) and China ($2 million), partially offset by a decrease in production in Canada ($8 million). DD&A rates increased due primarily to a proportional increase in production from higher cost properties in the United States ($167 million), Canada ($86 million), Trinidad ($12 million) and China ($8 million) and unfavorable changes in the Canadian exchange rate ($28 million), partially offset by a change in the fair value of the contingent consideration liability ($24 million).

DD&A expenses associated with other property, plant and equipment were $15 million higher in 2010 than in 2009 primarily due to natural gas gathering systems and processing plants being placed in service in the Rocky Mountain area ($10 million) and the Fort Worth Basin Barnett Shale area ($4 million).

G&A expenses of $280 million in 2010 were $32 million higher than 2009 due primarily to higher employee-related costs ($10 million), higher legal and other professional fees ($7 million) and higher information systems costs ($3 million).

Net interest expense of $130 million in 2010 increased $29 million from $101 million in 2009 primarily due to a higher average debt balance ($50 million), partially offset by higher capitalized interest ($21 million).

Gathering and processing costs increased $9 million to $67 million in 2010 compared to $58 million in 2009. The increase reflects increased activities in the Fort Worth Basin Barnett Shale area ($6 million) and the Rocky Mountain area ($3 million).

Exploration costs of $187 million in 2010 increased $17 million from $170 million for the same prior year period primarily due to increased employee-related costs in the United States.

Impairments of $743 million in 2010 increased $437 million from $306 million in 2009 primarily due to increased impairments of proved properties and other property, plant and equipment in Canada. EOG recorded impairments of proved properties and other property, plant and equipment of $526 million and $94 million in 2010 and 2009, respectively. In 2010, EOG recorded a pretax impairment of $280 million to adjust certain Canadian shallow natural gas assets sold to estimated fair value less estimated cost to sell (see Note 16 to Consolidated Financial Statements). Additionally, EOG recorded pretax impairments of $170 million in the fourth quarter of 2010 related to certain North American onshore and offshore natural gas assets.

Taxes other than income in 2010 increased $143 million to $317 million (6.5% of wellhead revenues) from $174 million (5.1% of wellhead revenues) in 2009. The increase in taxes other than income was primarily due to increased severance/production taxes primarily as a result of increased wellhead revenues in the United States ($56 million), Trinidad ($22 million) and Canada ($6 million); a decrease in credits available to EOG in 2010 for Texas high cost gas severance tax rate reductions as a result of fewer wells qualifying for such credit ($43 million); and higher ad valorem/property taxes in the United States ($14 million).

Other income, net was $14 million in 2010 compared to $2 million in 2009. The increase of $12 million was primarily due to higher equity income from ammonia plants in Trinidad ($9 million).

Income tax provision of $247 million in 2010 decreased $78 million compared to 2009 due primarily to decreased pretax income. The net effective tax rate for 2010 increased to 61% from 37% in 2009. The increase in the 2010 net effective tax rate was primarily due to higher state income taxes and to the tax effects of increased earnings in Trinidad and Canadian book losses, which resulted largely from the impairment of certain Canadian shallow natural gas assets. The statutory tax rates in the United States and Trinidad are higher than the Canadian statutory rate.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2011 were funds generated from operations, net proceeds from issuances of long-term debt, proceeds from asset sales, net proceeds from the sale of Common Stock, proceeds from stock options exercised and employee stock purchase plan activity, 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; dividend payments to stockholders; and repayments of debt.

2011 compared to 2010. Net cash provided by operating activities of $4,578 million in 2011 increased $1,869 million from $2,709 million in 2010 primarily reflecting an increase in wellhead revenues ($1,977 million), favorable changes in the net cash flow from the settlement of financial commodity derivative contracts ($174 million) and favorable changes in working capital and other assets and liabilities ($137 million), partially offset by an increase in cash operating expenses ($383 million), an increase in cash paid for interest expense ($40 million) and an increase in cash paid for income taxes ($27 million).

Net cash used in investing activities of $5,755 million in 2011 increased by $852 million from $4,903 million for the same period of 2010 due primarily to an increase in additions to oil and gas properties ($1,084 million), unfavorable changes in working capital associated with investing activities ($446 million) and an increase in additions to other property, plant and equipment ($286 million), partially offset by an increase in proceeds from sales of assets ($761 million) and the acquisition of Galveston LNG Inc. in 2010 ($210 million).

Net cash provided by financing activities of $1,009 million in 2011 included net proceeds from the sale of Common Stock ($1,388 million) and proceeds from stock options exercised and employee stock purchase plan activity ($36 million). Cash used in financing activities during 2011 included the repayment of long-term debt ($220 million), cash dividend payments ($167 million), treasury stock purchases in connection with stock compensation plans ($24 million) and debt issuance costs associated with the establishment of the 2011 Facility ($5 million).

2010 compared to 2009. Net cash provided by operating activities of $2,709 million in 2010 decreased $213 million from $2,922 million in 2009 primarily reflecting an unfavorable change in the net cash flow from the settlement of financial commodity derivative contracts ($1,271 million), an increase in cash operating expenses ($410 million), an increase in cash paid for income taxes ($182 million), an increase in cash paid for interest expense ($46 million), and unfavorable changes in working capital and other assets and liabilities ($7 million), partially offset by an increase in wellhead revenues ($1,482 million).

Net cash used in investing activities of $4,903 million in 2010 increased by $1,488 million from $3,415 million for the same period of 2009 due primarily to an increase in additions to oil and gas properties ($2,034 million); the acquisition of Galveston LNG Inc. ($210 million); and an increase in additions to other property, plant and equipment ($45 million); partially offset by an increase in proceeds from sales of assets ($461 million); and favorable changes in working capital associated with investing activities ($327 million).

Net cash provided by financing activities of $2,303 million in 2010 included proceeds from the issuances of long-term debt ($2,479 million) and proceeds from stock options exercised and employee stock purchase plan activity ($35 million). Cash used in financing activities during 2010 included cash dividend payments ($153 million), the repayment of long-term debt ($37 million), treasury stock purchases in connection with stock compensation plans ($11 million) and debt issuance costs ($8 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2011, 2010 and 2009 (in millions):

	Actual		
	2011	**2010**	**2009**
Expenditure Category			
Capital			
Drilling and Facilities	$ 5,878	$ 4,634	$ 2,417
Leasehold Acquisitions	301	399	424
Property Acquisitions [(1)]	4	18	707
Capitalized Interest	58	76	55
Subtotal	6,241	5,127	3,603
Exploration Costs	172	187	170
Dry Hole Costs	53	72	51
Exploration and Development Expenditures	6,466	5,386	3,824
Asset Retirement Costs	133	72	84
Total Exploration and Development Expenditures	6,599	5,458	3,908
Other Property, Plant and Equipment [(2)]	656	581	326
Total Expenditures	**$ 7,255**	**$ 6,039**	**$ 4,234**

(1) In 2009, property acquisitions included non-cash additions of $353 million related to a property exchange transaction in the Rocky Mountain area. In 2009 and 2010, property acquisitions also included non-cash additions for contingent consideration, with estimated fair values of $35 million and $3 million, respectively, related to the acquisition of the Haynesville Assets (see Note 16 to Consolidated Financial Statements).

(2) In 2010, other property, plant and equipment included $210 million for the acquisition of Galveston LNG Inc. (see Note 16 to Consolidated Financial Statements).

Exploration and development expenditures of $6,466 million for 2011 were $1,080 million higher than the prior year due primarily to increased drilling and facilities expenditures in the United States ($1,421 million) and the United Kingdom ($62 million), increased dry hole costs in China ($22 million) and unfavorable changes in the foreign currency exchange rate in Canada ($15 million). These increases were partially offset by decreased drilling and facilities expenditures in Canada ($181 million) and China ($70 million); decreased leasehold acquisitions expenditures in the United States ($90 million) and Canada ($8 million); decreased dry hole costs in the United Kingdom ($22 million), Canada ($14 million) and Trinidad ($5 million); decreased capitalized interest in the United States ($18 million); decreased property acquisition expenditures in the United States ($14 million); and decreased exploration geological and geophysical expenditures in the United States ($13 million). The 2011 exploration and development expenditures of $6,466 million included $5,797 million in development, $607 million in exploration, $58 million in capitalized interest and $4 million in property acquisitions. In 2011, other property, plant and equipment expenditures included $231 million for sand mine and sand processing assets. The 2010 exploration and development expenditures of $5,386 million included $4,366 million in development, $926 million in exploration, $76 million in capitalized interest and $18 million in property acquisitions. In 2010, other property, plant and equipment expenditures included $210 million for the acquisition of Galveston LNG Inc. The 2009 exploration and development expenditures of $3,824 million included $2,082 million in development, $980 million in exploration, $707 million in property acquisitions and $55 million in capitalized interest. In 2009, other property, plant and equipment primarily related to gathering and processing assets in the Fort Worth Basin Barnett Shale and Rocky Mountain areas.

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 its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

During 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $626 million, which included net realized gains of $181 million. During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. See Note 11 to Consolidated Financial Statements.

Commodity Derivative Contracts. The total fair value of EOG's crude oil and natural gas derivative contracts is reflected on the Consolidated Balance Sheets at December 31, 2011 as an asset of $486 million. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at February 24, 2012, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel ($/Bbl).

Crude Oil Derivative Contracts		
	Volume (Bbld)	Weighted Average Price ($/Bbl)
2012 (1)		
January 2012 (closed)	34,000	$104.95
February 2012	34,000	104.95
March 1, 2012 through June 30, 2012	52,000	105.80
July 1, 2012 through August 31, 2012	35,000	105.56
September 1, 2012 through December 31, 2012	17,000	103.59

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 17,000 Bbld are exercisable on June 29, 2012. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 17,000 Bbld at an average price of $106.31 per barrel for the period July 1, 2012 through December 31, 2012. Options covering a notional volume of 18,000 Bbld are exercisable on August 31, 2012. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 18,000 Bbld at an average price of $107.42 per barrel for the period September 1, 2012 through February 28, 2013.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts as of February 24, 2012, with notional volumes expressed in MMBtu per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Derivative Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2012 (1)		
January 2012 through February 29, 2012 (closed)	525,000	$5.44
March 1, 2012 through December 31, 2012	525,000	5.44
2013 (2)		
January 1, 2013 through December 31, 2013	150,000	$4.79
2014 (2)		
January 1, 2014 through December 31, 2014	150,000	$4.79

(1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for the period from March 1, 2012 through December 31, 2012.

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu for each month of 2013 and 2014.

Financing

EOG's debt-to-total capitalization ratio was 28% at December 31, 2011 compared to 34% at December 31, 2010. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

During 2011, total debt outstanding decreased $220 million to $5,040 million. The estimated fair value of EOG's debt at December 31, 2011 and 2010 was $5,657 million and $5,602 million, respectively. 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, 2011, a 1% decline in interest rates would result in a $315 million increase in the estimated fair value of the fixed rate obligations. See Note 2 to Consolidated Financial Statements.

During 2011, EOG utilized cash provided by operating activities, proceeds from the public offering of EOG Common Stock described below and proceeds from asset sales and cash provided by borrowings from its commercial paper program to fund its capital programs. While EOG maintains a $2.0 billion commercial paper program, the maximum outstanding at any time during 2011 was $182 million, and the amount outstanding at year-end was zero. The average borrowings outstanding under the commercial paper program were $3 million during the year 2011. EOG considers this excess availability, which is backed by the 2011 Facility described in Note 2 to Consolidated Financial Statements, to be ample to meet its ongoing operating needs.

On March 7, 2011, EOG completed the sale of 13,570,000 shares of Common Stock at the public offering price of $105.50 per share. Net proceeds from the sale of the Common Stock were approximately $1,388 million after deducting the underwriting discount and offering expenses. Proceeds from the sale were used for general corporate purposes, including funding capital expenditures.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2011 (in thousands):

Contractual Obligations [1]	**Total**	**2012**	**2013 - 2014**	**2015 - 2016**	**2017 & Beyond**
Current and Long-Term Debt	$ 5,040,000	$ -	$ 900,000	$ 900,000	$ 3,240,000
Non-Cancelable Operating Leases	502,076	173,061	97,515	68,231	163,269
Interest Payments on Long-Term Debt	1,570,811	234,918	436,864	366,370	532,659
Transportation and Storage Service Commitments [2]	3,256,452	359,686	779,585	844,944	1,272,237
Drilling Rig Commitments [3]	339,206	230,541	105,319	3,346	-
Seismic Purchase Obligations	4,087	4,087	-	-	-
Fracturing Services Obligations	338,585	301,851	27,827	8,907	-
Other Purchase Obligations	120,108	116,533	3,489	86	-
Total Contractual Obligations	**$ 11,171,325**	**$ 1,420,677**	**$ 2,350,599**	**$ 2,191,884**	**$ 5,208,165**

(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 asset retirement obligations (see Notes 5, 6 and 14, respectively, to Consolidated Financial Statements).

(2) Amounts shown are based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2011. 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 2011, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Canada, Trinidad, the United Kingdom, China and Argentina. The foreign currency most significant to EOG's operations during 2011 was the Canadian dollar. The fluctuation of the Canadian dollar in 2011 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 exchange rate impacts that may result from the notes offered by one of its 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 the Derivatives and Hedging Topic of the ASC. Under those provisions, as of December 31, 2011, EOG recorded the fair value of the foreign currency swap of $52 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 on the Consolidated Statements of Income and Comprehensive Income. The after-tax net impact from the foreign currency swap transaction resulted in a negative change of $1 million for the year ended December 31, 2011. The change is included in Accumulated Other Comprehensive Income in the Stockholders' Equity section of the Consolidated Balance Sheets.

Outlook

Pricing. Crude oil and natural gas prices have been volatile, and this volatility is expected to continue. As a result of 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 crude oil and condensate, natural gas liquids, natural gas, ammonia and methanol prices in the future. The market price of crude oil and condensate, natural gas liquids and natural gas in 2012 will impact the amount of cash generated from operating activities, which will in turn impact EOG's financial position. See Item 1A. Risk Factors.

Including the impact of EOG's 2012 crude oil derivative contracts and based on EOG's tax position, EOG's price sensitivity in 2012 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the related change in natural gas liquids price, is approximately $31 million for net income and $46 million for cash flows from operating activities. Including the impact of EOG's 2012 natural gas derivative contracts, based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2012 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $11 million for net income and $16 million for cash flows from operating activities. For information regarding EOG's crude oil and natural gas financial commodity derivative contracts as of February 24, 2012, see "Derivative Transactions" above.

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 particular, EOG will be focused on United States and Canada crude oil and liquids-rich drilling activity in its Eagle Ford, Bakken and Three Forks, Barnett Combo, Wolfcamp and Leonard Shale plays and, to a much lesser extent, United States and Canada natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays to hold acreage. 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.

The total anticipated 2012 capital expenditures of $7.4 to $7.6 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 and the sale of certain non-core assets. EOG expects capital expenditures to be greater than cash flow from operating activities for 2012. EOG's business plan includes selling certain non-core assets in 2012 to partially cover the anticipated shortfall. However, EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under the 2011 Facility and equity and debt offerings.

Operations. EOG expects to increase overall production in 2012 by 5.5% over 2011 levels. Total liquids production is expected to increase by 30%, comprised of an increase in crude oil and condensate and natural gas liquids production of 30% and 30%, respectively. North American natural gas production is expected to decrease by 11% from 2011 levels.

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 require 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 crude oil and condensate, natural gas liquids and natural gas 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. For related discussion, see ITEM 1A. Risk Factors.

Oil and Gas Exploration Costs

EOG accounts for its crude oil and natural gas 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. 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 discovered 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, 2011 and 2010, EOG had exploratory drilling costs related to projects that have been deferred for more than one year (see Note 15 to Consolidated Financial Statements). These costs meet the accounting requirements outlined above for continued capitalization. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of EOG's calculation of depreciation, depletion and amortization 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 for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. 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.

Oil and gas properties are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the ASC. 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 the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Depreciation and amortization of other property, plant and equipment is calculated on a straight-line basis over the estimated useful life of the asset.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. 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 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 generally calculated using the income approach described in the Fair Value Measurements and Disclosures Topic of the ASC. In certain instances, EOG utilizes accepted bids as the basis for determining fair value. Estimates of future undiscounted cash flows require significant judgment. Crude oil and natural gas prices have exhibited significant volatility in the past, and EOG expects that volatility to continue in the future. During the past five years, West Texas Intermediate crude oil spot prices have fluctuated from approximately $30 per barrel (Bbl) to $145 per Bbl and Henry Hub natural gas spot prices have ranged from approximately $1.83 per million British thermal units (MMBtu) to $13 per MMBtu. EOG's proved reserves estimates, including the timing of future production, are also subject to significant judgment, and are frequently revised (upwards and downwards) as more information becomes available. In the future, if actual crude oil and/or natural gas prices and/or actual production diverge negatively from EOG's current estimates, impairment charges may be necessary.

Stock-Based Compensation

In accounting for stock-based compensation, 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 Common 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 on 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, returns, budgets, reserves, 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, generate income or cash flows or pay dividends 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 any of these expectations will be achieved (in full or at all) 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, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, and to produce reserves and achieve anticipated production levels from, its existing and future crude oil and natural gas exploration and development projects, given the risks and uncertainties and capital expenditure requirements inherent in drilling, completing and operating crude oil and natural gas wells and the potential for interruptions of development and production, whether involuntary or intentional as a result of market or other conditions;
- the extent to which EOG is successful in its efforts to market its crude oil, natural gas and related commodity production;

- 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;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- EOG's ability to effectively integrate acquired crude oil and natural gas 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;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- 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;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation of production, gathering, processing, compression and transportation 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, and to otherwise satisfy its capital expenditure requirements;
- the extent and effect of any hedging activities engaged in by EOG;
- 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;
- political developments around the world, including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors", on pages 15 through 23 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 or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, 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, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances 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, 2011. 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, 2011 in ensuring that information that is required to be disclosed in the reports EOG 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 adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls 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, 2011. 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, 2011. 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 schedule and effectiveness of internal control over financial reporting is set forth beginning 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, 2011 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 2012 Annual Meeting of Stockholders to be filed not later than April 29, 2012 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 Securities Exchange Act of 1934, as amended, 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, principal financial officer and principal 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 officer, principal 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 any amendments to the Code of Conduct or Code of Ethics, and any waivers with respect to the Code of Conduct or Code of Ethics granted to EOG's principal executive officer, principal financial officer, principal accounting officer, any of our controllers or any of our other employees performing similar functions, 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. There have been no waivers granted with respect to EOG's Code of Conduct or Code of Ethics.

ITEM 11. ***Executive Compensation***

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2012 Annual Meeting of Stockholders to be filed not later than April 29, 2012. The Compensation Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

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 2012 Annual Meeting of Stockholders to be filed not later than April 29, 2012.

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. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the 2008 Plan was approved, pursuant to which the number of shares of common stock available for future grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards under the 2008 Plan was increased by an additional 6.9 million shares, to an aggregate maximum of 12.9 million shares plus shares underlying forfeited or cancelled grants under the 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).

At the 2010 Annual Meeting, an amendment to the Employee Stock Purchase Plan (ESPP) was approved to increase the shares available for grant by 1.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG.

The 1992 Stock Plan and the 1993 Nonemployee Directors Stock Option Plan have also been approved by EOG's stockholders. Plans that have not been approved by EOG's stockholders are described below.

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 shares of restricted stock and/or restricted stock units under the 1994 Stock Plan 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. Shares of restricted stock, 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, vestings of restricted stock units granted to non-employee directors and 401(k) refunds resulting from excess deferrals in the EOG Resources, Inc. 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 in accordance with the Deferral Plan and the individual's deferral election. A total of 120,000 shares have been registered for issuance under the Deferral Plan. As of December 31, 2011, 118,985 phantom shares had been issued.

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, in each case as of December 31, 2011.

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	12,004,029	$76.98	6,202,142 (1) (2)
Equity Compensation Plans Not Approved by EOG Stockholders	695,350	$24.78	1,015 (3)
Total	**12,699,379**	**$74.12**	**6,203,157**

(1) Of these securities, 789,650 shares remain available for purchase under the ESPP.
(2) Of these securities, 1,386,908 could be issued as restricted stock or restricted stock units under the 2008 Plan.
(3) Represents shares that remain available for issuance under the Deferral Plan (as described above).

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 2012 Annual Meeting of Stockholders to be filed not later than April 29, 2012.

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 2012 Annual Meeting of Stockholders to be filed not later than April 29, 2012.

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-7 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 on 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 adequate 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, circumvention of controls 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.

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 periodically 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, 2011. In making this assessment, EOG 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, 2011.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements (including financial statement schedule) of EOG, audit EOG's internal control over financial reporting and issue a report thereon. In the conduct of the audits, 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 audits were valid and appropriate. Their audits were made in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 24, 2012

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, 2011 and 2010, 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, 2011. 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, 2011, 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 schedules, 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 EOG Resources, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Effective December 31, 2009, the Company adopted the updated oil and gas reserve estimation and disclosure rules.

/S/ DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2012

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

Year Ended December 31	**2011**	**2010**	**2009**
Net Operating Revenues			
Crude Oil and Condensate	$ 3,838,284	$ 1,998,771	$ 1,089,711
Natural Gas Liquids	779,364	462,345	258,799
Natural Gas	2,240,540	2,420,099	2,050,963
Gains on Mark-to-Market Commodity Derivative Contracts	626,053	61,912	431,757
Gathering, Processing and Marketing	2,115,792	909,680	407,116
Gains on Asset Dispositions, Net	492,909	223,538	535,436
Other, Net	33,173	23,551	13,177
Total	10,126,115	6,099,896	4,786,959
Operating Expenses			
Lease and Well	941,954	698,430	579,290
Transportation Costs	430,322	385,189	283,329
Gathering and Processing Costs	80,727	66,758	57,632
Exploration Costs	171,658	187,381	169,592
Dry Hole Costs	53,230	72,486	51,243
Impairments	1,031,037	742,647	305,832
Marketing Costs	2,072,137	884,212	397,375
Depreciation, Depletion and Amortization	2,516,381	1,941,926	1,549,188
General and Administrative	304,811	280,474	248,274
Taxes Other Than Income	410,549	317,074	174,363
Total	8,012,806	5,576,577	3,816,118
Operating Income	2,113,309	523,319	970,841
Other Income, Net	6,853	14,243	2,071
Income Before Interest Expense and Income Taxes	2,120,162	537,562	972,912
Interest Expense			
Incurred	268,104	205,886	155,820
Capitalized	(57,741)	(76,300)	(54,919)
Net Interest Expense	210,363	129,586	100,901
Income Before Income Taxes	1,909,799	407,976	872,011
Income Tax Provision	818,676	247,322	325,384
Net Income	$ 1,091,123	$ 160,654	$ 546,627
Net Income Per Share			
Basic	$ 4.15	$ 0.64	$ 2.20
Diluted	$ 4.10	$ 0.63	$ 2.17
Dividends Declared per Common Share	$ 0.64	$ 0.62	$ 0.58
Average Number of Common Shares			
Basic	262,735	250,876	248,996
Diluted	266,268	254,500	251,884
Comprehensive Income			
Net Income	$ 1,091,123	$ 160,654	$ 546,627
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	(32,597)	96,179	308,286
Foreign Currency Swap Transaction	(1,571)	4,447	6,336
Income Tax Related to Foreign Currency Swap Transaction	404	(1,203)	(1,519)
Interest Rate Swap Transaction	(5,223)	1,843	-
Income Tax Related to Interest Rate Swap Transaction	1,878	(664)	-
Other	(1,216)	(251)	(1,170)
Comprehensive Income	**$ 1,052,798**	**$ 261,005**	**$ 858,560**

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	2011	2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 615,726	$ 788,853
Accounts Receivable, Net	1,451,227	1,113,279
Inventories	590,594	415,792
Assets from Price Risk Management Activities	450,730	48,153
Income Taxes Receivable	26,609	54,916
Deferred Income Taxes	-	9,260
Other	119,052	97,193
Total	3,253,938	2,527,446
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	33,664,435	29,263,809
Other Property, Plant and Equipment	2,149,989	1,733,073
Total Property, Plant and Equipment	35,814,424	30,996,882
Less: Accumulated Depreciation, Depletion and Amortization	(14,525,600)	(12,315,982)
Total Property, Plant and Equipment, Net	21,288,824	18,680,900
Other Assets	296,035	415,887
Total Assets	**$ 24,838,797**	**$ 21,624,233**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 2,033,615	$ 1,664,944
Accrued Taxes Payable	147,105	82,168
Dividends Payable	42,578	38,962
Liabilities from Price Risk Management Activities	-	28,339
Deferred Income Taxes	135,989	41,703
Current Portion of Long-Term Debt	-	220,000
Other	163,032	143,983
Total	2,522,319	2,220,099
Long-Term Debt	5,009,166	5,003,341
Other Liabilities	799,189	667,455
Deferred Income Taxes	3,867,219	3,501,706
Commitments and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 269,323,084 Shares and 254,223,521 Shares Issued at December 31, 2011 and 2010, respectively	202,693	202,542
Additional Paid in Capital	2,272,052	729,992
Accumulated Other Comprehensive Income	401,746	440,071
Retained Earnings	9,789,345	8,870,179
Common Stock Held in Treasury, 303,633 Shares and 146,186 Shares at December 31, 2011 and 2010, respectively	(24,932)	(11,152)
Total Stockholders' Equity	12,640,904	10,231,632
Total Liabilities and Stockholders' Equity	**$ 24,838,797**	**$ 21,624,233**

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)

	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Stockholders' Equity
Balance at December 31, 2008	$202,498	$ 323,805	$ 27,787	$8,466,143	$ (5,736)	$ 9,014,497
Net Income	-	-	-	546,627	-	546,627
Common Stock Issued Under Stock Plans	3	18,641	-	-	-	18,644
Common Stock Dividends Declared, $0.58 Per Share	-	-	-	(146,023)	-	(146,023)
Foreign Currency Translation Adjustments	-	-	308,286	-	-	308,286
Foreign Currency Swap Transaction, Net of Tax	-	-	4,817	-	-	4,817
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	(1,170)	-	-	(1,170)
Change in Treasury Stock - Stock Compensation Plans, Net	-	(4,240)	-	-	(4,923)	(9,163)
Excess Tax Benefits from Stock-Based Compensation	-	76,134	-	-	-	76,134
Restricted Stock and Restricted Stock Units, Net	10	(2,483)	-	-	2,473	-
Stock-Based Compensation Expenses	-	95,037	-	-	-	95,037
Shares Issued for Property Acquisition	15	89,566	-	-	-	89,581
Treasury Stock Issued as Compensation	-	242	-	-	533	775
Balance at December 31, 2009	202,526	596,702	339,720	8,866,747	(7,653)	9,998,042
Net Income	-	-	-	160,654	-	160,654
Common Stock Issued Under Stock Plans	10	34,552	-	-	-	34,562
Common Stock Dividends Declared, $0.62 Per Share	-	-	-	(157,222)	-	(157,222)
Foreign Currency Translation Adjustments	-	-	96,179	-	-	96,179
Foreign Currency Swap Transaction, Net of Tax	-	-	3,244	-	-	3,244
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	(251)	-	-	(251)
Interest Rate Swap, Net of Tax	-	-	1,179	-	-	1,179
Change in Treasury Stock - Stock Compensation Plans, Net	-	(7,257)	-	-	(4,039)	(11,296)
Excess Tax Expense from Stock-Based Compensation	-	(837)	-	-	-	(837)
Restricted Stock and Restricted Stock Units, Net	6	(505)	-	-	499	-
Stock-Based Compensation Expenses	-	107,314	-	-	-	107,314
Treasury Stock Issued as Compensation	-	23	-	-	41	64
Balance at December 31, 2010	202,542	729,992	440,071	8,870,179	(11,152)	10,231,632
Net Income	-	-	-	1,091,123	-	1,091,123
Common Stock Issued Under Stock Plans	10	35,903	-	-	-	35,913
Common Stock Dividends Declared, $0.64 Per Share	-	-	-	(171,957)	-	(171,957)
Foreign Currency Translation Adjustments	-	-	(32,597)	-	-	(32,597)
Foreign Currency Swap Transaction, Net of Tax	-	-	(1,167)	-	-	(1,167)
Defined Benefit Pension and Post Retirement Plans, Net of Tax	-	-	(1,216)	-	-	(1,216)
Interest Rate Swap, Net of Tax	-	-	(3,345)	-	-	(3,345)
Change in Treasury Stock - Stock Compensation Plans, Net	-	(18,622)	-	-	(5,413)	(24,035)
Excess Tax Expense from Stock-Based Compensation	-	25	-	-	-	25
Restricted Stock and Restricted Stock Units, Net	5	8,410	-	-	(8,415)	-
Stock-Based Compensation Expenses	-	128,205	-	-	-	128,205
Common Stock Sold	136	1,388,129	-	-	-	1,388,265
Treasury Stock Issued as Compensation	-	10	-	-	48	58
Balance at December 31, 2011	$202,693	$2,272,052	$401,746	$9,789,345	$(24,932)	$12,640,904

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	2011	2010	2009
Cash Flows from Operating Activities			
Reconciliation of Net Income to Net Cash Provided by Operating Activities:			
Net Income	$ 1,091,123	$ 160,654	$ 546,627
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	2,516,381	1,941,926	1,549,188
Impairments	1,031,037	742,647	305,832
Stock-Based Compensation Expenses	128,345	107,378	95,180
Deferred Income Taxes	499,300	76,245	174,392
Gains on Asset Dispositions, Net	(492,909)	(223,538)	(535,436)
Other, Net	15,139	(468)	6,761
Dry Hole Costs	53,230	72,486	51,243
Mark-to-Market Commodity Derivative Contracts			
Total Gains	(626,053)	(61,912)	(431,757)
Realized Gains	180,701	7,033	1,277,584
Excess Tax Benefits from Stock-Based Compensation	-	-	(76,134)
Other, Net	26,454	17,273	18,862
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(339,780)	(339,126)	(47,818)
Inventories	(176,623)	(171,791)	(50,146)
Accounts Payable	351,087	654,688	(153,565)
Accrued Taxes Payable	92,589	(53,098)	90,929
Other Assets	(23,625)	(32,169)	(5,515)
Other Liabilities	14,986	19,342	(12,305)
Changes in Components of Working Capital Associated with Investing and Financing Activities	237,028	(208,968)	118,517
Net Cash Provided by Operating Activities	4,578,410	2,708,602	2,922,439
Investing Cash Flows			
Additions to Oil and Gas Properties	(6,294,397)	(5,210,612)	(3,176,783)
Additions to Other Property, Plant and Equipment	(656,415)	(370,770)	(326,226)
Acquisition of Galveston LNG Inc.	-	(210,000)	-
Proceeds from Sales of Assets	1,433,137	672,593	212,000
Changes in Components of Working Capital Associated with Investing Activities	(237,267)	208,933	(118,221)
Other, Net	-	7,082	(5,321)
Net Cash Used in Investing Activities	(5,754,942)	(4,902,774)	(3,414,551)
Financing Cash Flows			
Common Stock Sold	1,388,265	-	-
Long-Term Debt Borrowings	-	2,478,659	900,000
Long-Term Debt Repayments	(220,000)	(37,000)	-
Dividends Paid	(167,169)	(153,240)	(142,260)
Excess Tax Benefits from Stock-Based Compensation	-	-	76,134
Treasury Stock Purchased	(23,922)	(11,295)	(10,986)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	35,913	34,560	20,465
Debt Issuance Costs	(4,787)	(8,300)	(8,895)
Other, Net	239	35	(296)
Net Cash Provided by Financing Activities	1,008,539	2,303,419	834,162
Effect of Exchange Rate Changes on Cash	(5,134)	(6,145)	12,390
(Decrease) Increase in Cash and Cash Equivalents	(173,127)	103,102	354,440
Cash and Cash Equivalents at Beginning of Year	788,853	685,751	331,311
Cash and Cash Equivalents at End of Year	**$ 615,726**	**$ 788,853**	**$ 685,751**

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 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 (U.S. GAAP) 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.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt, along with associated foreign currency and interest rate swaps. The carrying values of cash and cash equivalents, commodity derivative contracts, accounts receivable, foreign currency and interest rate swaps and accounts payable approximate fair value (see Notes 2 and 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 crude oil and natural gas 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 amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. 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 EOG has discovered proved commercial reserves. 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 discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made (see Note 15). Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, 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 for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. 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.

Oil and gas properties are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). 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.

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 generally calculated using the income approach described in the Fair Value Measurements and Disclosures Topic of the ASC. If applicable, EOG utilizes accepted bids as the basis for determining fair value.

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

Arrangements for crude oil and condensate, natural gas liquids and natural gas 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 crude oil and condensate, natural gas liquids and natural gas, as well as gathering fees associated with gathering third-party natural gas.

Other Property, Plant and Equipment. Other property, plant and equipment consists of gathering and processing assets, compressors, buildings and leasehold improvements, crude-by-rail assets, sand mine and sand processing assets, computer hardware and software, vehicles, and furniture and fixtures. Other property, plant and equipment is depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from 3 years to 40 years.

Capitalized Interest Costs. 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 phases and ceases once production begins. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings.

Accounting for Risk Management Activities. Derivative instruments are recorded on the balance sheet as either an asset or liability measured at fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ended December 31, 2011, EOG elected not to designate any of its financial commodity derivative instruments as accounting hedges, and accordingly, changes in the fair value of these outstanding derivative instruments are recognized as gains or losses in the period of change. The gains or losses are recorded as Gains on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact is reflected as cash flows from operating activities. See Note 11. EOG is party to a foreign currency swap transaction and an interest rate swap transaction (see Note 2). EOG employs net presentation of derivative assets and liabilities for financial reporting purposes when such assets and liabilities are with the same counterparty and subject to a master netting arrangement.

Income Taxes. Income taxes are accounted for using the asset and liability approach. 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. The United States dollar is the functional currency for all of EOG's consolidated subsidiaries except for certain of its Canadian subsidiaries, for which the functional currency is the Canadian dollar, and its United Kingdom subsidiary, for which the functional currency is the British pound. 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 on the Consolidated Balance Sheets. 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. 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 outstanding during the periods plus the assumed issuance of common shares for all potentially dilutive securities (see Note 8).

Stock-Based Compensation. 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 (see Note 6).

Recently Issued Accounting Standards. In May 2011, the FASB issued Accounting Standards Update (ASU) 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs". ASU 2011-04 amends the Fair Value Measurements and Disclosures Topic of the ASC to clarify the FASB's intent about the application of existing fair value measurement requirements and change certain principles or requirements for measuring fair value or disclosing information about fair value measurements. ASU 2011-04 is effective for interim and annual fiscal periods beginning after December 15, 2011. EOG does not expect that the adoption of ASU 2011-04 will have a material impact on its financial statements, but it may result in additional disclosures regarding fair value measurements.

In June 2011, the FASB issued ASU 2011-05 "Comprehensive Income (Topic 220): Presentation of Comprehensive Income." ASU 2011-05 is intended to increase the prominence of comprehensive income in the financial statements by requiring that an entity that reports items of comprehensive income do so in either one continuous or two consecutive financial statements. ASU 2011-05 also requires separate presentation on the face of the financial statements for items reclassified from other comprehensive income into net income. Subsequently, in December 2011, the FASB deferred the effective date of the provisions of ASU 2011-05 relating to the presentation of reclassification adjustments out of accumulated other comprehensive income. The provisions of ASU 2011-05 not deferred by the FASB are effective for interim and annual fiscal periods beginning after December 15, 2011. Retroactive application is required. EOG does not expect that the adoption of ASU 2011-05 will have a material impact on its financial statements, but it may result in additional disclosures regarding components of comprehensive income.

2. Long-Term Debt

Long-Term Debt at December 31, 2011 and 2010 consisted of the following (in thousands):

	2011	2010
6.125% Senior Notes due 2013	$ 400,000	$ 400,000
Floating Rate Senior Notes due 2014	350,000	350,000
2.95% Senior Notes due 2015	500,000	500,000
2.500% Senior Notes due 2016	400,000	400,000
5.875% Senior Notes due 2017	600,000	600,000
6.875% Senior Notes due 2018	350,000	350,000
5.625% Senior Notes due 2019	900,000	900,000
4.40% Senior Notes due 2020	500,000	500,000
4.100% Senior Notes due 2021	750,000	750,000
6.65% Senior Notes due 2028	140,000	140,000
7.00% Subsidiary Debt due 2011	-	220,000
4.75% Subsidiary Debt due 2014	150,000	150,000
Total Long-Term Debt	5,040,000	5,260,000
Less: Current Portion of Long-Term Debt	-	220,000
Unamortized Debt Discount	30,834	36,659
Total Long-Term Debt, Net	**$ 5,009,166**	**$ 5,003,341**

At December 31, 2011, the aggregate annual maturities of long-term debt were zero in 2012, $400 million in 2013, $500 million in 2014, $500 million in 2015 and $400 million in 2016. On December 1, 2011, a wholly-owned subsidiary of EOG repaid at maturity $220 million principal amount of 7% notes, plus accrued and unpaid interest. All subsidiary debt is guaranteed by EOG.

During 2011 and 2010, EOG utilized commercial paper and short-term borrowings under uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper or under uncommitted credit facilities at December 31, 2011. The average borrowings outstanding under the commercial paper program and uncommitted credit facilities were $3 million and zero, respectively, during the year ended December 31, 2011. The weighted average interest rates for commercial paper borrowings for 2011 was 0.34%.

On October 11, 2011, EOG entered into a $2.0 billion senior unsecured Revolving Credit Agreement (2011 Facility) among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto (Banks) and the other parties thereto. The 2011 Facility replaces EOG's $1.0 billion senior unsecured Revolving Credit Agreement, dated as of June 28, 2005, which had a scheduled maturity date of June 28, 2012 (2005 Facility), and EOG's $1.0 billion senior unsecured Revolving Credit Agreement, dated as of September 10, 2010, which had a scheduled maturity date of September 10, 2013 (2010 Facility). There were no borrowings outstanding under either the 2005 Facility or the 2010 Facility as of the closing of the 2011 Facility and the termination of the 2005 Facility and the 2010 Facility. The 2011 Facility has a scheduled maturity date of October 11, 2016 and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods, subject to, among certain other terms and conditions, the consent of the Banks holding greater than 50% of the commitments then outstanding under the 2011 Facility. The 2011 Facility commits the Banks to provide advances up to an aggregate principal amount of $2.0 billion at any one time outstanding, with an option for EOG to request increases in the aggregate commitments to an amount not to exceed $3.0 billion, subject to certain terms and conditions. Advances under the 2011 Facility will accrue interest based, at EOG's option, on either the London InterBank Offering Rate (LIBOR) plus an applicable margin (Eurodollar rate), or the base rate (as defined in the 2011 Facility) plus an applicable margin. The applicable margin used in connection with interest rates and fees will be based on EOG's credit rating at the applicable time. At December 31, 2011, there were no borrowings or letters of credit outstanding under the 2011 Facility. The Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2011 Facility, would have been 1.17% and 3.25%, respectively.

The 2011 Facility contains representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a total debt-to-total capitalization ratio of no greater than 65%. At December 31, 2011 and during the year then ended, EOG believes that it was in compliance with this financial debt covenant.

On November 23, 2010, EOG completed its public offering of $400 million aggregate principal amount of 2.500% Senior Notes due 2016 (2016 Notes), $750 million aggregate principal amount of 4.100% Senior Notes due 2021 (2021 Notes) (together, the Fixed Rate Notes) and $350 million aggregate principal amount of Floating Rate Senior Notes due 2014 (the Floating Rate Notes). Interest on the Fixed Rate Notes is payable semiannually. Interest on the Floating Rate Notes is payable quarterly and is based on LIBOR plus 0.75% per annum. The interest rate on the Floating Rate Notes resets quarterly on the interest payment dates. Net proceeds from the offering of approximately $1,487 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings. Contemporaneously with the offering of the Floating Rate Notes, EOG entered into an interest rate swap to fix the interest rate on the Floating Rate Notes at 1.87% (see Note 11).

On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings.

On May 12, 2010, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, repaid at maturity the remaining $37 million outstanding balance of its $75 million Revolving Credit Agreement, thereby canceling this agreement. The weighted average interest rate for the amount outstanding during the year ended December 31, 2010 was 2.74%.

The 2.95% Senior Notes due 2015, the 2016 Notes, the 4.40% Senior Notes due 2020 and the 2021 Notes were issued through public offerings and have effective interest rates of 3.148%, 2.698%, 4.565%, and 4.276%, respectively.

EOG Resources Canada Inc., a wholly-owned subsidiary of EOG, has outstanding notes with an aggregate principal amount of $150 million, an interest rate of 4.75% and a maturity date of March 15, 2014. 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. EOG accounts for the foreign currency swap transaction using the hedge accounting method (see Note 11).

Fair Value of Debt. At December 31, 2011 and 2010, EOG had outstanding $5,040 million and $5,260 million, respectively, aggregate principal amount of debt, which had estimated fair values of approximately $5,657 million and $5,602 million, respectively. 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.

3. Stockholders' Equity

Common Stock. On March 7, 2011, EOG completed the public offering and sale of 13,570,000 shares of EOG common stock, par value $0.01 per share (Common Stock), at the public offering price of $105.50 per share. Net proceeds from the sale of the Common Stock were approximately $1,388 million after deducting the underwriting discount and offering expenses. Proceeds from the sale were used for general corporate purposes, including funding capital expenditures.

In September 2001, EOG's Board of Directors (Board) authorized the purchase of an aggregate maximum of 10 million shares of Common Stock that superseded all previous authorizations. At December 31, 2011, 6,386,200 shares remained available for purchase under this authorization. EOG last purchased shares of its Common Stock under this authorization in March 2003. In addition, shares of 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, 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 do not count against 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 shares of Common Stock shall be required.

The Board increased the quarterly cash dividend on the Common Stock to $0.155 per share on February 9, 2010, $0.16 per share on February 17, 2011 and to $0.17 per share on February 16, 2012.

The following summarizes Common Stock activity for each of the years ended December 31, 2009, 2010 and 2011 (in thousands):

	Common Shares		
	Issued	**Treasury**	**Outstanding**
Balance at December 31, 2008	249,759	(127)	249,632
Common Stock Issued Under Equity Compensation Plans	1,347	-	1,347
Treasury Stock Purchased [(1)]	-	(168)	(168)
Common Stock Issued Under Employee Stock Purchase Plan	71	-	71
Treasury Stock Issued Under Other Equity Compensation Plans	-	177	177
Common Stock Issued for Property Acquisition	1,450	-	1,450
Balance at December 31, 2009	252,627	(118)	252,509
Common Stock Issued Under Equity Compensation Plans	1,482	-	1,482
Treasury Stock Purchased [(1)]	-	(115)	(115)
Common Stock Issued Under Employee Stock Purchase Plan	114	-	114
Treasury Stock Issued Under Other Equity Compensation Plans	-	87	87
Balance at December 31, 2010	254,223	(146)	254,077
Common Stock Issued Under Equity Compensation Plans	1,395	-	1,395
Treasury Stock Purchased [(1)]	-	(267)	(267)
Common Stock Issued Under Employee Stock Purchase Plan	135	-	135
Treasury Stock Issued Under Other Equity Compensation Plans	-	109	109
Common Stock Sold	13,570	-	13,570
Balance at December 31, 2011	269,323	(304)	269,019

(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, the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options.

Preferred Stock. EOG currently has one authorized series of preferred stock. In February 2000, EOG's Board, in connection with a rights agreement, authorized 1,500,000 shares of the Series E Junior Participating Preferred Stock (Series E). 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 the Common Stock effected in March 2005. As of December 31, 2011, there were no shares of the Series E outstanding. The rights agreement and the related preferred share purchase rights expired on February 24, 2010.

4. Other Income, Net

Other income, net for 2011 included equity income from investments in ammonia plants in Trinidad ($17 million), operating losses on EOG's investment in Pacific Trail Pipelines (PTP) in Canada ($5 million) and losses on sales of warehouse stock ($5 million). Other income, net for 2010 included equity income from investments in ammonia plants in Trinidad ($13 million), net foreign currency transaction gains ($4 million) and losses on sales of warehouse stock ($4 million).

5. Income Taxes

The principal components of EOG's net deferred income tax liabilities at December 31, 2011 and 2010 were as follows (in thousands):

	2011	2010
Current Deferred Income Tax Assets (Liabilities)		
Commodity Hedging Contracts	$ -	$ (7,141)
Deferred Compensation Plans	-	13,216
Other	-	3,185
Total Net Current Deferred Income Tax Assets	**$ -**	**$ 9,260**
Noncurrent Deferred Income Tax Assets (Liabilities)		
United Kingdom Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ (57,850)	$ (16,611)
United Kingdom Net Operating Loss	62,477	17,329
United Kingdom Other	314	226
Total Net Noncurrent Deferred Income Tax Assets	**$ 4,941**	**$ 944**
Current Deferred Income Tax (Assets) Liabilities		
Commodity Hedging Contracts	$ 158,302	$ -
Deferred Compensation Plans	(28,346)	-
Timing Differences Associated with Different Year-ends in Foreign Jurisdictions	6,251	41,027
Other	(218)	676
Total Net Current Deferred Income Tax Liabilities	**$ 135,989**	**$ 41,703**
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 5,485,436	$ 4,373,110
Non-Producing Leasehold Costs	(66,926)	(78,846)
Seismic Costs Capitalized for Tax	(111,862)	(92,901)
Equity Awards	(120,852)	(99,447)
Capitalized Interest	106,265	94,957
Net Operating Loss	(1,152,386)	(498,893)
Alternative Minimum Tax Credit Carryforward	(298,350)	(214,873)
Other	25,894	18,599
Total Net Noncurrent Deferred Income Tax Liabilities	**$ 3,867,219**	**$ 3,501,706**
Total Net Deferred Income Tax Liabilities	**$ 3,998,267**	**$ 3,533,205**

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

	2011	2010	2009
United States	$ 2,156,147	$ 646,495	$ 784,248
Foreign	(246,348)	(238,519)	87,763
Total	**$ 1,909,799**	**$ 407,976**	**$ 872,011**

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

	2011	2010	2009
Current:			
Federal	$ 94,244	$ 17,154	$ 95,194
State	1,083	(1,642)	8,783
Foreign	224,049	155,565	47,015
Total	319,376	171,077	150,992
Deferred:			
Federal	608,181	190,602	166,045
State	40,321	60,619	31,580
Foreign	(149,202)	(174,976)	(23,233)
Total	499,300	76,245	174,392
Income Tax Provision	**$ 818,676**	**$ 247,322**	**$ 325,384**

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

	2011	2010	2009
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	1.41	9.39	3.00
Income Tax Provision Related to Foreign Operations	0.88	(0.03)	(1.40)
Income Tax Provision Related to Trinidad Operations	3.37	6.26	0.60
Canadian Shallow Natural Gas Impairments	1.85	9.49	-
Other	0.36	0.51	0.11
Effective Income Tax Rate	42.87%	60.62%	37.31%

The difference in the effective tax rate and the United States federal statutory rate of 35% is attributed principally to state and foreign income taxes. The decrease in the state tax expense is attributable largely to the redetermination of the deferred state tax liability, which was reduced to reflect lower statutory state tax rates in North Dakota. Foreign taxes had a smaller effect on EOG's worldwide tax rate due to smaller Canadian impairments, which are tax-effected at a statutory rate of 27%, and to higher domestic earnings.

The balance of unrecognized tax benefits at December 31, 2011 was $33 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. Currently, 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, Trinidad and China for taxable years before 2005, 2007, 2010, 2004 and 2008, respectively.

EOG's foreign subsidiaries' undistributed earnings of approximately $2.3 billion at December 31, 2011 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. The amount of such additional taxes would be dependent on several factors, including the size and timing of the distribution, the particular foreign jurisdiction from which the distribution is made, and the availability of foreign tax credits. As a result, the determination of the potential amount of unrecognized withholding and deferred income taxes is not practicable, though additional taxes resulting from a repatriation of foreign earnings could be significant.

In 2011, EOG generated a regular tax net operating loss (NOL) of $1.8 billion. This NOL, along with the 2010 NOL of $1.4 billion, is expected to be carried forward and applied against regular taxable income in future periods. To the extent not utilized, these NOL carryforwards will expire in 2030 and 2031, respectively. Additionally, as of December 31, 2011, EOG had state income tax NOLs of approximately $700 million, which, if unused, expire between 2015 and 2031. The Stock Compensation Topic of the ASC provides that when settlement of a stock award contributes to a NOL carryforward, neither the associated excess tax benefit nor the credit to additional paid in capital (APIC) should be recorded until the stock award deduction reduces income taxes payable. Upon utilization of the NOLs in future periods, a benefit of $40 million will be reflected in APIC (including $23 million and $17 million related to 2011 and 2010, respectively). In 2011, EOG paid alternative minimum tax (AMT) of $104 million. The AMT paid in 2011, along with AMT of $194 million paid in prior years, will be carried forward indefinitely as a credit available to offset regular income taxes in future periods.

The ability of EOG to utilize both the regular tax NOL carryfowards and the AMT credit carryforwards to reduce regular federal taxable income and federal income taxes, respectively, may become subject to various limitations under the Internal Revenue Code. Such limitations may arise if certain ownership changes (as defined for income tax purposes) were to occur. As of December 31, 2011, we do not believe that an ownership change has occurred which would limit either carryforward.

During 2011, EOG's United Kingdom subsidiary incurred a tax NOL of approximately $71 million which, along with the 2010 NOL of $30 million, will be carried forward indefinitely. In July 2011, the United Kingdom increased the statutory income tax rate applying to oil and gas activities from 50% to 62%, effective March 2011. In December 2011, the United Kingdom increased from 6% to 10% a statutory deduction referred to as "Uplift," which is an upward adjustment to certain unused NOLs. The increase in the Uplift percentage is effective January 1, 2012. These two changes did not have a material impact on EOG's 2011 earnings or cash flow.

6. Employee Benefit Plans

Stock-Based Compensation

During 2011, EOG maintained various stock-based compensation plans as discussed below. EOG recognizes compensation expense on grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock and restricted stock units and grants made under its Employee Stock Purchase Plan (ESPP). Stock-based compensation expense is calculated based upon the grant date estimated fair value of the awards, net of forfeitures, based upon EOG's historical employee turnover rate. 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 on 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, 2011, 2010 and 2009 was as follows (in millions):

	2011	2010	2009
Lease and Well	$ 33	$ 27	$ 23
Gathering and Processing Costs	1	1	-
Exploration Costs	26	24	21
General and Administrative	68	55	51
Total	$ 128	$ 107	$ 95

The EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (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 12.9 million shares plus shares underlying forfeited or cancelled grants under prior stock plans. At December 31, 2011, approximately 5.4 million shares of Common Stock 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 either previously authorized unissued shares or treasury shares, to the extent treasury shares are available.

During 2011, 2010 and 2009, EOG issued shares in connection with stock option/SAR exercises, restricted stock grants, restricted stock unit releases and ESPP purchases. EOG recognized, as an adjustment to APIC, federal income tax (expense)/benefits of $25,000, $(1) million and $76 million for 2011, 2010 and 2009, 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. 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 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 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 ESPP grants is estimated using the Black-Scholes-Merton model. The fair value of stock option grants and SAR grants is estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $48 million, $41 million and $38 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2011, 2010 and 2009 were as follows:

	Stock Options/SARs			**ESPP**		
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
Weighted Average Fair Value of Grants	$29.92	$32.12	$30.13	$22.75	$25.45	$25.78
Expected Volatility	40.96%	39.70%	41.90%	29.82%	38.30%	78.89%
Risk-Free Interest Rate	0.58%	0.87%	1.42%	0.14%	0.18%	0.25%
Dividend Yield	0.70%	0.70%	0.70%	0.70%	0.70%	1.00%
Expected Life	5.6 yrs	5.5 yrs	5.5 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, 2011, 2010 and 2009 (stock options and SARs in thousands):

	2011		2010		2009	
	Number of Stock Options/ SARs	**Weighted Average Grant Price**	**Number of Stock Options/ SARs**	**Weighted Average Grant Price**	**Number Of Stock Options/ SARs**	**Weighted Average Grant Price**
Outstanding at January 1	8,445	$64.49	8,335	$57.08	7,802	$52.56
Granted	1,509	85.29	1,450	93.07	1,270	80.95
Exercised (1)	(1,399)	50.86	(1,144)	43.38	(636)	46.56
Forfeited	(181)	87.74	(196)	84.22	(101)	74.07
Outstanding at December 31	8,374	70.01	8,445	64.49	8,335	57.08
Stock Options/SARs Exercisable at December 31	5,148	59.19	5,439	51.71	5,394	44.45

(1) The total intrinsic value of stock options/SARs exercised during the years 2011, 2010 and 2009 was $78.4 million, $66.0 million and $21.4 million, respectively. The intrinsic value is based upon the difference between the market price of Common Stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2011, there were 8,123,226 stock options/SARs vested or expected to vest with a weighted average grant price of $69.48 per share, an intrinsic value of $238.5 million and a weighted average remaining contractual life of 3.6 years.

The following table summarizes certain information for the stock options and SARs outstanding at December 31, 2011 (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)**
$16.00 to $ 48.99	1,431	1	$20.30		1,431	1	$20.30	
49.00 to 69.99	1,623	1	61.99		1,609	1	61.94	
70.00 to 81.99	1,674	4	78.17		1,159	4	76.66	
82.00 to 88.99	2,174	6	85.44		576	4	88.73	
89.00 to 136.99	1,472	5	95.09		373	5	96.56	
	8,374	4	70.01	$241,474	5,148	2	59.19	$203,646

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

At December 31, 2011, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $87.9 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.8 years.

At December 31, 2011, approximately 790,000 shares of Common Stock remained available for issuance under the ESPP. The following table summarizes ESPP activities for the years ended December 31, 2011, 2010 and 2009 (in thousands, except number of participants):

	2011	2010	2009
Approximate Number of Participants	1,525	1,236	1,128
Shares Purchased	135	114	72
Aggregate Purchase Price	$ 10,947	$ 9,172	$ 4,150

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, shares of Common Stock are released to the employee. Upon vesting, restricted stock units are converted into shares of Common Stock and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $80 million, $66 million and $57 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2011, 2010 and 2009 (shares and units in thousands):

	2011		2010		2009	
	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	4,009	$79.13	3,636	$73.69	3,048	$70.24
Granted	932	90.87	850	93.39	1,197	63.13
Released (1)	(457)	66.10	(364)	58.00	(553)	31.35
Forfeited	(244)	82.45	(113)	79.37	(56)	78.18
Outstanding at December 31 (2)	4,240	82.93	4,009	79.13	3,636	73.69

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2011, 2010 and 2009 was $44.4 million, $35.2 million and $36.9 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, 2011 and 2010 was approximately $417.7 million and $366.4 million, respectively.

At December 31, 2011, unrecognized compensation expense related to restricted stock and restricted stock units totaled $132.6 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.4 years.

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 (such plans were merged into a single plan, effective as of January 1, 2012). 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 $27.1 million, $23.4 million and $21.8 million for 2011, 2010 and 2009, 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. 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. 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, Trinidadian and United Kingdom subsidiaries. EOG's combined contributions to these plans were $2.5 million, $2.8 million and $2.6 million for 2011, 2010 and 2009, respectively.

For the Canadian and Trinidadian defined benefit pension plans, the benefit obligation, fair value of plan assets and prepaid/(accrued) benefit cost totaled $11.3 million, $8.2 million and $(1.6) million, respectively, at December 31, 2011 and $10.3 million, $8.7 million and $(0.8) million, respectively, at December 31, 2010.

Postretirement Health Care. EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents, the costs of which are not material.

7. Commitments and Contingencies

Letters of Credit. At December 31, 2011, EOG had standby letters of credit and guarantees outstanding totaling approximately $585 million, of which $150 million represents guarantees of subsidiary indebtedness (see Note 2) and $435 million primarily represents guarantees of payment obligations on behalf of subsidiaries. At December 31, 2010, EOG had standby letters of credit and guarantees outstanding totaling approximately $657 million, of which $370 million represents guarantees of subsidiary indebtedness (see Note 2) and $287 million primarily represents guarantees of payment obligations on behalf of subsidiaries. As of February 24, 2012, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2011, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase obligations, fracturing services obligations, other purchase obligations and transportation and storage service commitments, based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2011, are as follows (in thousands):

		Total Minimum Commitments
2012	$	1,185,759
2013 - 2014		1,013,735
2015 - 2016		925,514
2017 and beyond		1,435,506
	$	**4,560,514**

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2026. Rental expenses associated with existing leases amounted to $149 million, $95 million and $77 million for 2011, 2010 and 2009, 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, 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. 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

The following table sets forth the computation of Net Income Per Share for the years ended December 31, 2011, 2010 and 2009 (in thousands, except per share data):

		2011		**2010**		**2009**
Numerator for Basic and Diluted Earnings per Share -						
Net Income	$	1,091,123	$	160,654	$	546,627
Denominator for Basic Earnings per Share -						
Weighted Average Shares		262,735		250,876		248,996
Potential Dilutive Common Shares -						
Stock Options/SARs		1,707		1,991		1,691
Restricted Stock and Restricted Stock Units		1,826		1,633		1,197
Denominator for Diluted Earnings per Share -						
Adjusted Diluted Weighted Average Shares		266,268		254,500		251,884
Net Income Per Share						
Basic	$	4.15	$	0.64	$	2.20
Diluted	$	4.10	$	0.63	$	2.17

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. The excluded stock options and SARs totaled 0.4 million, 0.3 million and 2.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

9. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	2011	2010	2009
Interest, Net of Capitalized Interest	$ 186,718	$ 146,731	$ 100,939
Income Taxes, Net of Refunds Received	$ 260,224	$ 233,462	$ 51,684

EOG's accrued capital expenditures at December 31, 2011, 2010 and 2009 were $663 million, $709 million and $334 million, respectively.

Non-cash investing and financing activities for the year ended December 31, 2009 included the following (see Note 16):

- the issuance of 1,450,000 shares of Common Stock valued at $90 million at the transaction closing date in connection with EOG's purchase of certain proved developed and undeveloped reserves and unproved acreage; and
- non-cash additions to EOG's oil and gas properties in the amount of $353 million in connection with EOG's asset exchange agreement in respect of certain natural gas-related properties.

10. Business Segment Information

EOG's operations are all crude oil and natural gas exploration and production related. The Segment Reporting Topic of the ASC 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 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, 2011, 2010 and 2009 (in thousands):

	United States	Canada	Trinidad	Other International [1]	Total
2011					
Crude Oil and Condensate	$ 3,458,248	$ 264,895	$ 112,554	$ 2,587	$ 3,838,284
Natural Gas Liquids	762,730	16,634	-	-	779,364
Natural Gas	1,593,964	178,324	442,589	25,663	2,240,540
Gains on Mark-to-Market Commodity Derivative Contracts	626,053	-	-	-	626,053
Gathering, Processing and Marketing	2,115,768	-	24	-	2,115,792
Gains on Asset Dispositions, Net	475,878	17,033	(2)	-	492,909
Other, Net	32,329	258	586	-	33,173
Net Operating Revenues [2]	9,064,970	477,144	555,751	28,250	10,126,115
Depreciation, Depletion and Amortization	2,131,706	260,084	107,141	17,450	2,516,381
Operating Income (Loss)	2,252,508	(459,520)	383,992	(63,671)	2,113,309
Interest Income	436	342	101	140	1,019
Other Income (Expense)	(6,480)	(2,375)	18,755	(4,066)	5,834
Net Interest Expense	214,360	23,085	-	(27,082)	210,363
Income (Loss) Before Income Taxes	2,032,104	(484,638)	402,848	(40,515)	1,909,799
Income Tax Provision (Benefit)	732,362	(125,474)	204,698	7,090	818,676
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	5,790,590	259,634	132,159	58,784	6,241,167
Total Property, Plant and Equipment, Net	18,711,774	1,760,066	627,794	189,190	21,288,824
Total Assets	21,313,158	2,131,949	1,085,664	308,026	24,838,797

	United States	Canada	Trinidad	Other International (1)	Total
2010					
Crude Oil and Condensate	$ 1,700,770	$ 178,349	$ 117,605	$ 2,047	$ 1,998,771
Natural Gas Liquids	448,647	13,698	-	-	462,345
Natural Gas	1,778,823	285,369	330,247	25,660	2,420,099
Gains on Mark-to-Market Commodity Derivative Contracts	61,912	-	-	-	61,912
Gathering, Processing and Marketing	909,660	-	20	-	909,680
Gains on Asset Dispositions, Net	196,774	23,112	3,652	-	223,538
Other, Net	19,886	(31)	3,696	-	23,551
Net Operating Revenues (2)	5,116,472	500,497	455,220	27,707	6,099,896
Depreciation, Depletion and Amortization	1,539,240	315,849	71,085	15,752	1,941,926
Operating Income (Loss)	787,422	(516,874)	312,128	(59,357)	523,319
Interest Income	152	387	120	164	823
Other Income (Expense)	(3,905)	2,067	14,022	1,236	13,420
Net Interest Expense	112,226	34,350	448	(17,438)	129,586
Income (Loss) Before Income Taxes	671,443	(548,770)	325,822	(40,519)	407,976
Income Tax Provision (Benefit)	255,945	(146,495)	140,934	(3,062)	247,322
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,491,897	446,626	134,198	65,405	5,138,126
Total Property, Plant and Equipment, Net	15,747,808	2,189,961	595,970	147,161	18,680,900
Total Assets	17,762,533	2,598,412	954,391	308,897	21,624,233
2009					
Crude Oil and Condensate	$ 945,224	$ 86,140	$ 57,089	$ 1,258	$ 1,089,711
Natural Gas Liquids	246,821	11,978	-	-	258,799
Natural Gas	1,540,042	315,792	172,560	22,569	2,050,963
Gains on Mark-to-Market Commodity Derivative Contracts	431,757	-	-	-	431,757
Gathering, Processing and Marketing	407,097	-	19	-	407,116
Gains on Asset Dispositions, Net	535,295	141	-	-	535,436
Other, Net	9,693	(16)	3,500	-	13,177
Net Operating Revenues (2)	4,115,929	414,035	233,168	23,827	4,786,959
Depreciation, Depletion and Amortization	1,282,180	211,514	47,119	8,375	1,549,188
Operating Income (Loss)	896,937	(31,767)	143,993	(38,322)	970,841
Interest Income	137	612	146	205	1,100
Other Income (Expense)	(7,396)	5,212	4,387	(1,232)	971
Net Interest Expense	84,411	28,934	1,332	(13,776)	100,901
Income (Loss) Before Income Taxes	805,267	(54,877)	147,194	(25,573)	872,011
Income Tax Provision (Benefit)	290,473	(27,073)	57,363	4,621	325,384
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	2,770,482	268,604	31,219	55,235	3,125,540
Total Property, Plant and Equipment, Net	12,769,240	2,740,473	532,989	96,523	16,139,225
Total Assets	14,108,129	2,888,949	813,901	307,688	18,118,667

(1) Other International primarily includes EOG's United Kingdom and China operations.
(2) EOG had no purchasers in 2011, 2010 or 2009 whose sales totaled 10 percent or more of consolidated Net Operating Revenues.

11. Risk Management Activities

Commodity Price 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 crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, collar, option and basis swap contracts, as a 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. 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 2011, 2010 and 2009, 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 2011, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $626 million, which included net realized gains of $181 million. During 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net realized gains of $7 million. During 2009, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $432 million, which included net realized losses of $1,278 million.

At December 31, 2011, the fair value of EOG's financial commodity derivative contracts was reflected on the Consolidated Balance Sheets as Current Assets - Assets from Price Risk Management Activities ($451 million) and Other Assets ($35 million). At December 31, 2010, the fair value of EOG's financial commodity derivative contracts was reflected on the Consolidated Balance Sheets as Current Assets - Assets From Price Risk Management Activities ($48 million), Other Assets ($20 million), Current Liabilities - Liabilities from Price Risk Management Activities ($28 million) and Other Liabilities ($1 million).

Commodity Derivative Contracts. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at December 31, 2011, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel ($/Bbl)

Crude Oil Derivative Contracts	Volume (Bbld)	Weighted Average Price ($/Bbl)
2012 (1)		
January 1, 2012 through June 30, 2012	34,000	$104.95
July 1, 2012 through December 31, 2012	17,000	103.59

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for an additional six-month period. Such options are exercisable on June 29, 2012. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 17,000 Bbld at an average price of $106.31 per barrel for the period July 1, 2012 through December 31, 2012.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts as of December 31, 2011, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Derivative Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2012 (1)		
January 2012 (closed)	525,000	$5.44
February 1, 2012 through December 31, 2012	525,000	5.44
2013 (2)		
January 1, 2013 through December 31, 2013	150,000	$4.79
2014 (2)		
January 1, 2014 through December 31, 2014	150,000	$4.79

(1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for the period from February 1, 2012 through December 31, 2012.

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu for each month of 2013 and 2014.

Foreign Currency Exchange Rate Derivative. EOG is party to a foreign currency aggregate swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the $150 million principal amount of notes issued by one of EOG's Canadian subsidiaries. EOG accounts for the foreign currency swap transaction using the hedge accounting method. The fair value of the foreign currency swap was $(52) million at December 31, 2011 and $(55) million at December 31, 2010. The after-tax net impact from the foreign currency swap resulted in a decrease in Other Comprehensive Income (OCI) of $1 million for the year ended December 31, 2011 and an increase in OCI of $3 million and $5 million for the years ended December 31, 2010 and 2009, respectively.

Interest Rate Derivative. EOG is a party to an interest rate swap transaction with a counterparty bank. The interest rate swap transaction was entered into in order to mitigate EOG's exposure to volatility in interest rates related to EOG's Floating Rate Notes issued on November 23, 2010. The interest rate swap has a notional amount of $350 million and a fair value of $(3) million and $2 million at December 31, 2011 and 2010, respectively. EOG accounts for the interest rate swap transaction using the hedge accounting method. The after-tax impact from the interest rate swap resulted in a decrease in OCI of $3 million for the year ended December 31, 2011 and an increase in OCI of $1 million for the year ended December 31, 2010.

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding derivative financial instruments at December 31, 2011 and 2010, respectively. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

Description	Location on Balance Sheet	Fair Value at December 31, 2011	Fair Value at December 31, 2010
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities	$ 451	$ 51
Noncurrent portion	Other Assets	$ 35	$ 18
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities	$ -	$ 30
Foreign currency swap -			
Noncurrent portion	Other Liabilities	$ 52	$ 55
Interest rate swap -			
Noncurrent portion	Other Assets	$ -	$ 2
	Other Liabilities	$ 3	$ -

Credit Risk. Notional contract amounts are used to express the magnitude of commodity price, foreign currency and interest rate swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 12). EOG evaluates its exposure to significant 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, 2011, no individual purchaser's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales accounted for 10% or more of the total balance. At December 31, 2010, a crude oil marketing company's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales accounted for 13% of the total balance. The related amounts were collected during early 2011. In 2011 and 2010, all natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago and all natural gas from EOG's China operations was sold to Petrochina Company Limited.

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 12 for the aggregate fair value of all derivative instruments with credit-risk related contingent features that are in a net liability position at December 31, 2011 and 2010. EOG had no collateral posted at both December 31, 2011 and 2010.

At December 31, 2011 and 2010, EOG had an allowance for doubtful accounts of $3 million and $14 million, respectively.

Substantially all of EOG's accounts receivable at December 31, 2011 and 2010 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 typically 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, 2011, 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 on the Consolidated Balance Sheets. An established fair value hierarchy 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. EOG gives consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value.

The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at December 31, 2011 and 2010 (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, 2011				
Financial Assets:				
Crude Oil and Natural Gas Derivative Contracts	$ -	$ 110	$ -	$ 110
Crude Oil and Natural Gas Options/Swaptions	-	376	-	376
Financial Liabilities:				
Foreign Currency Rate Swap	$ -	$ 52	$ -	$ 52
Interest Rate Swap	-	3	-	3
At December 31, 2010				
Financial Assets:				
Natural Gas Derivative Contracts	$ -	$ 62	$ -	$ 62
Natural Gas Options/Swaptions	-	6	-	6
Interest Rate Swap	-	2	-	2
Financial Liabilities:				
Crude Oil and Natural Gas Derivative Contracts	$ -	$ 29	$ -	$ 29
Foreign Currency Rate Swap	-	55	-	55
Contingent Consideration	-	-	14	14

The estimated fair value of crude oil and natural gas derivative contracts and interest rate swap contracts (see Note 11) was based upon forward commodity price and interest rate curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 14.

During 2011, proved oil and gas properties with a carrying amount of $1,450 million were written down to their fair value of $616 million, resulting in pretax impairment charges of $834 million. In connection with a $278 million impairment of certain natural gas assets in the U.S. during 2011, EOG utilized accepted bids as the basis for determining fair value. During 2010, proved oil and gas properties and other property, plant and equipment with a carrying amount of $1,013 million were written down to their fair value of $487 million, resulting in pretax impairment charges of $418 million in Canada, $107 million in the United States and $1 million in Trinidad. In connection with the $280 million impairment of shallow natural gas assets sold in Canada during the fourth quarter of 2010, EOG utilized accepted bids adjusted for estimates of customary closing adjustments less selling costs as the basis for determining fair value. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. In connection with certain impairments of proved oil and gas properties and other property, plant and equipment, EOG utilized an accepted offer from a third-party buyer.

13. Accounting for Certain Long-Lived Assets

EOG reviews its proved 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 2011, 2010 and 2009, such reviews indicated that unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows due primarily to lower commodity prices, downward reserve revisions, drilling of marginal or uneconomic wells, or development dry holes in certain producing fields. Several impairments over this period were recognized in connection with the signing of purchase and sale agreements. As a result, EOG recorded pretax charges of $403 million, $107 million and $90 million in the United States during 2011, 2010 and 2009, respectively, and $428 million, $418 million and $4 million in Canada during 2011, 2010 and 2009, respectively. Additionally, EOG recorded pretax charges of $3 million in Other International during 2011 and $1 million in Trinidad during 2010. 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 value using the income approach. If applicable, EOG utilizes accepted bids as the basis for determining fair value. Amortization of unproved oil and gas property costs, including amortization of capitalized interest, was $197 million, $217 million and $212 million for 2011, 2010 and 2009, respectively.

14. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the years ended December 31, 2011 and 2010 (in thousands):

	2011	2010
Carrying Amount at Beginning of Period	$ 498,288	$ 456,484
Liabilities Incurred	68,703	39,480
Liabilities Settled [1]	(66,129)	(30,763)
Accretion	27,907	25,456
Revisions	58,786	1,640
Foreign Currency Translations	(471)	5,991
Carrying Amount at End of Period	$ 587,084	$ 498,288
Current Portion	$ 29,527	$ 32,005
Noncurrent Portion	$ 557,557	$ 466,283

(1) Includes settlements related to asset sales.

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

15. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the years ended December 31, 2011, 2010 and 2009 are presented below (in thousands):

	2011	2010	2009
Balance at January 1	$ 99,801	$ 118,459	$ 85,255
Additions Pending the Determination of Proved Reserves	31,271	94,090	75,362
Reclassifications to Proved Properties	(29,227)	(93,333)	(40,614)
Charged to Dry Hole Costs	(42,178)	(20,267)	(11,223)
Foreign Currency Translations	1,444	852	9,679
Balance at December 31	$ 61,111	$ 99,801	$ 118,459

The following table provides an aging of capitalized exploratory well costs at December 31, 2011, 2010 and 2009 (in thousands, except well count):

	2011		2010		2009	
Capitalized exploratory well costs that have been capitalized for a period less than one year	$ 17,009		$ 43,408		$ 51,141	
Capitalized exploratory well costs that have been capitalized for a period greater than one year	44,102	(1)	56,393	(2)	67,318	(3)
Total	$ 61,111		$ 99,801		$ 118,459	
Number of exploratory wells that have been capitalized for a period greater than one year	4		4		4	

(1) Consists of costs related to an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($20 million), an East Irish Sea project in the U.K. ($9 million), a project in the Sichuan Basin, Sichuan Province, China ($9 million), and a shale project in British Columbia, Canada (B.C.) ($6 million). In the Central North Sea project, the operator and partners are currently negotiating processing and transportation terms with export infrastructure owners. The operator submitted a revised field development plan to the U.K. Department of Energy and Climate Change (DECC) during the second quarter of 2011 and anticipates receiving approval of this plan during the first half of 2012. In the East Irish Sea project, EOG submitted field development plans to the DECC during the first quarter of 2011 and expects regulatory approval during the first quarter of 2012. Installation of facilities, pipelines and drilling of development wells are planned for 2012 with initial production expected during the first quarter of 2013. The evaluation of the Sichuan Basin project is expected to be completed by mid-2012. In the B.C. shale project, EOG drilled four additional wells during the first half of 2011 and plans to drill seven wells in the first half of 2012 to retain land and further evaluate the project. The related well completion activities are not expected to commence until 2013 or later.

(2) Consists of costs related to an outside operated, offshore Central North Sea project in the U.K. ($21 million), an East Irish Sea project in the U.K. ($9 million), a project in the Sichuan Basin, Sichuan Province, China ($20 million), and a shale project in B.C. ($6 million).

(3) Consists of costs related to three shale projects in B.C. ($45 million) and an outside operated, offshore Central North Sea project in the U.K. ($22 million).

16. Acquisitions and Divestitures

During 2011, EOG received proceeds of approximately $1.4 billion from sales of producing properties and acreage and certain midstream assets, primarily in the Rocky Mountain area and Texas, and the sale of a portion of EOG's interest in the planned Kitimat liquefied natural gas (LNG) Terminal and the proposed Pacific Trail Pipelines (PTP). During 2010, EOG received proceeds of approximately $673 million from the sale of producing properties and acreage, primarily Canadian shallow natural gas assets and properties in the Rocky Mountain area, Texas, and Pennsylvania.

During the fourth quarter of 2010, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), paid $210 million to acquire Galveston LNG Inc., a Calgary-based corporation which owned 49% of the LNG export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia. In addition, Galveston LNG Inc. also owned a 24.5% interest in the PTP originating at Summit Lake, British Columbia. The pipeline is intended to link Western Canada's natural gas producing regions to the Kitimat LNG Terminal. At the time EOG completed the acquisition, an affiliate of Apache Corporation (Apache) owned 51% of the Kitimat LNG Terminal and a 25.5% interest in PTP. In connection with the acquisition, EOG recorded intangible assets related to certain leases, permits and other contracts. Such intangible assets are included in Other Assets on the Consolidated Balance Sheets. During the first quarter of 2011, EOGRC purchased an additional 24.5% interest in PTP for $25.2 million. A portion of the purchase price ($15.3 million) was paid at closing with the remaining amount to be paid contingent on the decision to proceed with the construction of the Kitimat LNG Terminal. Additionally, in March 2011, EOGRC and Apache, through a series of transactions, sold a portion of their interests in the Kitimat LNG Terminal and PTP to an affiliate of Encana Corporation (Encana). Subsequent to these transactions, ownership interests in both the Kitimat LNG Terminal and PTP are: Apache (operator) 40%, EOGRC 30% and Encana 30%. All future costs of the project will be paid by each party in proportion to its respective ownership percentage.

In the fourth quarter of 2010, EOG completed the sales of certain of its Canadian shallow natural gas assets in three separate transactions. Proceeds from the sales were approximately $344 million. In 2010, EOG recorded a pretax impairment of $280 million to adjust the shallow natural gas assets sold to estimated fair value less estimated cost to sell.

In December 2009, EOG and a third party entered into an asset exchange agreement whereby the two parties exchanged certain natural gas related properties in the Rocky Mountain area. In accordance with the provisions of the Business Combinations Topic of the ASC, EOG realized a pretax gain of $390 million on the exchange to reflect the excess of the fair value of the properties received over the book basis of the properties given up in the transaction.

In December 2009, EOG sold its crude oil and natural gas related assets located in California for consideration of $202 million. EOG realized a pretax gain in 2009 of approximately $146 million on the sale.

In October 2009, EOG entered into an agreement to acquire unproved acreage located in Nacogdoches County, Texas, within the Haynesville and Bossier Shale formations (Haynesville Assets). EOG acquired the unproved acreage at principal, supplemental and final closings held in October 2009, December 2009 and February 2010, respectively. The acquisition agreement provides for an additional one-time supplemental cash payment to the sellers of the Haynesville Assets that is contingent on the satisfaction of certain conditions (within a five-year period beginning on the principal closing date) set forth in the acquisition agreement with respect to future natural gas prices. The aggregate consideration recorded in 2009 and 2010 for the acquisition of the Haynesville Assets was $134 million and $18 million, respectively.

During the third quarter of 2009, EOG completed three transactions to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas. The aggregate purchase price of the transactions totaled $197 million, consisting of cash consideration of $107 million and 1,450,000 shares of EOG Common Stock valued at $89.6 million on the closing date of the applicable transaction.

Oil and Gas Producing Activities

In December 2008, the United States Securities and Exchange Commission (SEC) released a final rule, "Modernization of Oil and Gas Reporting," which amended the oil and gas reporting requirements effective January 1, 2010. The key revisions 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;
- the ability to use reliable technologies to determine and estimate reserves;
- permitting the optional disclosure of probable and possible reserves;
- reporting the independence and qualifications of the reserve preparer or auditor and filing a report as an exhibit when a third party is relied upon to prepare reserve estimates or conduct reserve audits; and
- disclosing the development of any proved undeveloped reserves, including the total quantity of proved undeveloped reserves at year-end, material changes to proved undeveloped reserves during the year, investments and progress toward the development of proved undeveloped reserves and an explanation of the reasons why material concentrations of proved undeveloped reserves have remained undeveloped for five years or more after disclosure as proved undeveloped reserves

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) No. 2010-03, "Oil and Gas Reserve Estimations and Disclosures" (ASU 2010-03). ASU 2010-03 aligns the current oil and gas reserve estimation and disclosure requirements of the Extractive Industries - Oil and Gas topic of the FASB Accounting Standards Codification (ASC Topic 932) with the changes required by the SEC final rule, "Modernization of Oil and Gas Reporting." ASU No. 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009.

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil, natural gas liquids and natural gas reserves is 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 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. See ITEM 1A. Risk Factors.

Proved reserves represent estimated quantities of crude oil, natural gas liquids and natural gas that geoscience and engineering data can estimate, with reasonable certainty, to be economically producible from a given day forward from known reservoirs under economic conditions, operating methods and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

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. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

In making estimates of proved undeveloped reserves, EOG's technical staff, including engineers and geoscientists, perform detailed technical analysis of each potential drilling location within its entire inventory of prospects. In making a determination as to which of these locations would penetrate undrilled portions of the formation that can be judged, with reasonable certainty, to be continuous and contain economically producible crude oil and natural gas, studies are conducted using numerous data elements and analysis techniques. EOG technical staff estimates the hydrocarbons in place, by mapping the entirety of the play in question using seismic techniques, typically employing two-dimensional and three-dimensional data. This analysis is integrated with other static data including, but not limited to, core analysis, mechanical properties of the formation, thermal maturity indicators, and well logs of existing penetrations. Highly specialized equipment is utilized to prepare rock samples in assessing microstructures which contribute to porosity and permeability.

Analysis of dynamic data is then incorporated to arrive at the estimated fractional recovery of hydrocarbons in place. Data and analysis techniques employed include, but are not limited to, well testing, static bottom hole pressure, flowing bottom hole pressure, historical production trends using extant completion techniques (typically from vertical wells), pressure transient analysis and rate transient analysis. Application of proprietary rate transient analysis techniques allow for quantification of estimates of contribution to production from both fractures and rock matrices.

The impact of optimal completion techniques is a key factor in determining if prospective locations are reasonably certain of being economically producible. EOG's technical staff estimates recovery improvement that might be achieved when employing horizontal wells with multi-stage fracture stimulation. In the early stages of development, EOG determines the optimal length of the horizontal lateral and multi-stage fracture stimulation using the aforementioned analysis techniques along with pilot drilling programs and gathering of microseismic data.

The process of analyzing static and dynamic data, well completion optimization and the results of early development provides the appropriate level of certainty as well as support for the economic producibilty of the plays in which proved undeveloped reserves are reflected. EOG has found that this approach has been proven effective based on successful application in analogous reservoirs in resource plays.

EOG has formulated development plans for all locations related to its proved undeveloped reserves.

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 reserves at December 31, 2011, 2010 and 2009 were based on studies performed by the engineering staff of EOG. The Engineering and Acquisitions Department is directly responsible for EOG's reserve evaluation process and consists of seven professionals, all of whom hold, at a minimum, bachelor's degrees in engineering, and three are Registered Professional Engineers. The Manager, Engineering and Acquisitions is the manager of this department and is the primary technical person responsible for this process. The Manager, Engineering and Acquisitions holds a Bachelor of Science degree in Petroleum Engineering, has 26 years of experience in reserve evaluations and is a Registered Professional Engineer in the State of Texas.

EOG's reserves estimation process is a collaborative effort coordinated by the Engineering and Acquisitions Department in compliance with EOG's internal controls for such process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including crude oil, natural gas liquids and natural gas prices, production costs, future capital expenditures and EOG's net ownership percentages are obtained from other departments within EOG. EOG's Internal Audit Department conducts testing with respect to such non-technical inputs. Additionally, EOG engages DeGolyer and MacNaughton (D&M), independent petroleum consultants, to perform independent reserves evaluation of select EOG properties of not less than 75% of proved reserves. EOG's Board of Directors requires that D&M's and EOG's reserve quantities for the properties evaluated by D&M vary by no more than 5% in the aggregate. Once completed, EOG's year-end reserves are presented to senior management, including the Chairman of the Board and Chief Executive Officer; the President; the Chief Operating Officer; and the Vice President and Chief Financial Officer for approval.

Opinions by D&M for the years ended December 31, 2011, 2010 and 2009 covered producing areas containing 85%, 77% and 81%, respectively, of proved reserves of EOG on a net-equivalent-barrel-of-oil basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's Engineering and Acquisitions Department for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil 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 and Acquisitions Department of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG. The report of D&M dated February 1, 2012, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 23.2 to this Annual Report on Form 10-K and incorporated herein by reference.

No major discovery or other favorable or adverse event subsequent to December 31, 2011 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, 2011, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2011, as estimated by the Engineering and Acquisitions Department of EOG:

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Trinidad	Other International [(1)]	Total
NET PROVED RESERVES					
Crude Oil (MBbl) [(2)]					
Net proved reserves at December 31, 2008	133,362	7,498	8,326	65	149,251
Revisions of previous estimates	4,402	(183)	(1,760)	17	2,476
Purchases in place	15,666	-	-	-	15,666
Extensions, discoveries and other additions	58,258	19,783	-	-	78,041
Sales in place	(5,742)	(20)	-	-	(5,762)
Production	(17,494)	(1,492)	(1,123)	(24)	(20,133)
Net proved reserves at December 31, 2009	188,452	25,586	5,443	58	219,539
Revisions of previous estimates	(8,313)	(104)	(754)	20	(9,151)
Purchases in place	13	-	-	-	13
Extensions, discoveries and other additions	199,479	3,198	1,751	48	204,476
Sales in place	(1,082)	(589)	-	-	(1,671)
Production	(23,092)	(2,455)	(1,709)	(28)	(27,284)
Net proved reserves at December 31, 2010	355,457	25,636	4,731	98	385,922
Revisions of previous estimates	(21,188)	(4,611)	18	25	(25,756)
Purchases in place	9	-	-	-	9
Extensions, discoveries and other additions	202,552	449	-	-	203,001
Sales in place	(4,301)	-	-	-	(4,301)
Production	(37,233)	(2,882)	(1,242)	(25)	(41,382)
Net proved reserves at December 31, 2011	**495,296**	**18,592**	**3,507**	**98**	**517,493**
Natural Gas Liquids (MBbl) [(2)]					
Net proved reserves at December 31, 2008	72,484	3,297	-	-	75,781
Revisions of previous estimates	6,109	(926)	-	-	5,183
Purchases in place	5,801	-	-	-	5,801
Extensions, discoveries and other additions	18,546	24	-	-	18,570
Sales in place	(3,231)	(30)	-	-	(3,261)
Production	(8,220)	(393)	-	-	(8,613)
Net proved reserves at December 31, 2009	91,489	1,972	-	-	93,461
Revisions of previous estimates	27,490	(196)	-	-	27,294
Purchases in place	-	-	-	-	-
Extensions, discoveries and other additions	42,221	21	-	-	42,242
Sales in place	(2)	(6)	-	-	(8)
Production	(10,764)	(316)	-	-	(11,080)
Net proved reserves at December 31, 2010	150,434	1,475	-	-	151,909
Revisions of previous estimates	35,999	43	-	-	36,042
Purchases in place	17	-	-	-	17
Extensions, discoveries and other additions	65,288	-	-	-	65,288
Sales in place	(10,008)	-	-	-	(10,008)
Production	(15,144)	(316)	-	-	(15,460)
Net proved reserves at December 31, 2011	**226,586**	**1,202**	**-**	**-**	**227,788**

	United States	Canada	Trinidad	Other International (1)	Total
Natural Gas (Bcf) (3)					
Net proved reserves at December 31, 2008	4,889.0	1,237.2	1,198.1	14.9	7,339.2
Revisions of previous estimates	(378.0)	(447.2)	(104.9)	3.0	(927.1)
Purchases in place	450.8	-	-	-	450.8
Extensions, discoveries and other additions	1,925.0	846.5	-	-	2,771.5
Sales in place	(114.4)	(5.1)	-	-	(119.5)
Production	(422.3)	(81.9)	(107.4)	(5.2)	(616.8)
Net proved reserves at December 31, 2009	6,350.1	1,549.5	985.8	12.7	8,898.1
Revisions of previous estimates	(222.7)	(29.9)	(88.6)	1.9	(339.3)
Purchases in place	-	-	-	-	-
Extensions, discoveries and other additions	821.3	3.4	63.0	7.9	895.6
Sales in place	(34.6)	(316.2)	-	-	(350.8)
Production	(422.6)	(73.0)	(132.6)	(5.2)	(633.4)
Net proved reserves at December 31, 2010	6,491.5	1,133.8	827.6	17.3	8,470.2
Revisions of previous estimates	(344.0)	(49.8)	(24.2)	1.3	(416.7)
Purchases in place	3.0	-	-	-	3.0
Extensions, discoveries and other additions	634.6	-	74.7	4.5	713.8
Sales in place	(323.6)	-	-	-	(323.6)
Production	(415.7)	(48.1)	(127.4)	(4.6)	(595.8)
Net proved reserves at December 31, 2011	**6,045.8**	**1,035.9**	**750.7**	**18.5**	**7,850.9**
Oil Equivalents (MBoe) (2)					
Net proved reserves at December 31, 2008	1,020,671	217,002	208,013	2,548	1,448,234
Revisions of previous estimates	(52,487)	(75,638)	(19,250)	515	(146,860)
Purchases in place	96,605	-	-	-	96,605
Extensions, discoveries and other additions	397,642	160,882	-	-	558,524
Sales in place	(28,032)	(898)	-	-	(28,930)
Production	(96,107)	(15,540)	(19,016)	(891)	(131,554)
Net proved reserves at December 31, 2009	1,338,292	285,808	169,747	2,172	1,796,019
Revisions of previous estimates	(17,945)	(5,288)	(15,513)	342	(38,404)
Purchases in place	14	-	-	-	14
Extensions, discoveries and other additions	378,582	3,789	12,250	1,363	395,984
Sales in place	(6,860)	(53,288)	-	-	(60,148)
Production	(104,277)	(14,937)	(23,815)	(901)	(143,930)
Net proved reserves at December 31, 2010	1,587,806	216,084	142,669	2,976	1,949,535
Revisions of previous estimates	(42,526)	(12,865)	(4,011)	239	(59,163)
Purchases in place	521	-	-	-	521
Extensions, discoveries and other additions	373,602	448	12,455	750	387,255
Sales in place	(68,247)	-	-	-	(68,247)
Production	(121,648)	(11,219)	(22,484)	(787)	(156,138)
Net proved reserves at December 31, 2011	**1,729,508**	**192,448**	**128,629**	**3,178**	**2,053,763**

(1) Other International includes EOG's United Kingdom and China operations.

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

(3) Billion cubic feet.

During 2011, EOG added 387 million barrels of oil equivalent (MMBoe) of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Eagle Ford, Barnett Combo and Bakken shale plays. Approximately 69% of the 2011 reserve additions were crude oil and condensate and natural gas liquids and over 96% were in the United States. Sales in place of 68 MMBoe were primarily related to the disposition of certain producing natural gas assets in East Texas, the Rocky Mountain region and other producing basins in the United States. Revisions of previous estimates of negative 59 MMBoe for 2011 included a negative revision of 16 MMBoe primarily due to a decrease in the average natural gas price used in the December 31, 2011 reserves estimation as compared to the price used in the prior year estimate. Revisions other than price resulted from negative performance revisions for certain crude oil and natural gas properties in the United States, Canada and Trinidad.

During 2010, EOG added 396 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Eagle Ford, Bakken, Barnett Combo and Haynesville shale plays. Approximately 62% of the 2010 reserve additions were crude oil and condensate and natural gas liquids and over 95% were in the United States. Sales in place of 60 MMBoe were primarily related to the Canadian shallow natural gas assets and certain producing natural gas assets in East Texas. Revisions of previous estimates of negative 38 MMBoe for 2010 included a positive revision of 28 MMBoe primarily due to an increase in the average natural gas price used in the December 31, 2010 reserves estimation as compared to the price used in the prior year estimate. Revisions other than price resulted from negative performance revisions for certain natural gas properties in the United States, Canada and Trinidad and the removal of proved undeveloped natural gas drilling locations from the five-year drilling plan to focus on crude oil and liquids-rich drilling as part of EOG's overall strategy.

During 2009, EOG added 558 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Haynesville, Horn River, Barnett, Bakken and Marcellus shale plays. Approximately 82% of the 2009 reserve additions were natural gas. EOG's revisions of previous estimates for 2009 of negative 147 MMBoe included negative revisions of approximately 131 MMBoe, which were primarily due to the decrease in the average natural gas price used in the December 31, 2009 reserves estimation as compared to the price used in the prior year estimate. Purchases in place include the reserves acquired in the Rocky Mountain property exchange and the acquisition of certain Barnett Shale Combo Assets in Montague and Cooke Counties, Texas. Sales in place primarily include reserves from the properties relinquished in the Rocky Mountain property exchange and from the California asset sale. See Note 16 to Consolidated Financial Statements.

	United States	Canada	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES					
Liquids (MBbl) (2)					
December 31, 2008	159,607	10,416	6,756	65	176,844
December 31, 2009	189,322	10,831	3,966	58	204,177
December 31, 2010	253,308	12,758	3,853	98	270,017
December 31, 2011	338,144	9,220	2,657	97	350,118
Natural Gas (Bcf) (3)					
December 31, 2008	3,544.7	1,103.7	889.0	14.9	5,552.3
December 31, 2009	3,330.1	681.0	609.4	12.7	4,633.2
December 31, 2010	3,519.7	401.6	519.2	17.3	4,457.8
December 31, 2011	3,234.9	295.8	606.3	18.6	4,155.6
Oil Equivalents (MBoe) (2)					
December 31, 2008	750,389	194,360	154,939	2,548	1,102,236
December 31, 2009	744,339	124,323	105,540	2,172	976,374
December 31, 2010	839,928	79,701	90,382	2,976	1,012,987
December 31, 2011	877,301	58,524	103,710	3,178	1,042,713
NET PROVED UNDEVELOPED RESERVES					
Liquids (MBbl) (2)					
December 31, 2008	46,239	379	1,570	-	48,188
December 31, 2009	90,619	16,727	1,477	-	108,823
December 31, 2010	252,583	14,352	879	-	267,814
December 31, 2011	383,739	10,574	850	-	395,163
Natural Gas (Bcf) (3)					
December 31, 2008	1,344.3	133.6	309.0	-	1,786.9
December 31, 2009	3,020.0	868.5	376.4	-	4,264.9
December 31, 2010	2,971.7	732.2	308.5	-	4,012.4
December 31, 2011	2,810.8	740.1	144.4	-	3,695.3
Oil Equivalents (MBoe) (2)					
December 31, 2008	270,282	22,642	53,074	-	345,998
December 31, 2009	593,953	161,486	64,207	-	819,646
December 31, 2010	747,878	136,383	52,287	-	936,548
December 31, 2011	852,207	133,924	24,919	-	1,011,050

(1) Other International includes EOG's United Kingdom and China operations.

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

(3) Billion cubic feet.

For the twelve-month period ended December 31, 2011, total proved undeveloped reserves (PUDs) increased by 75 MMBoe to 1,011 MMBoe. EOG added approximately 36 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on page F-34 of this Annual Report on Form 10-K), EOG added 199 MMBoe. The proved undeveloped reserve additions were primarily in the Eagle Ford and Barnett Combo shale plays, and over 78% of the additions were crude oil and condensate and natural gas liquids. During 2011, EOG drilled and transferred 144 MMBoe of PUDs to proved developed reserves at a total capital cost of $1,619 million. Revisions of PUDs totaled negative 7 MMBoe, primarily due to removal of certain natural gas PUDs from the five-year drilling plan. During 2011, EOG sold 9 MMBoe of PUDs.

For the twelve-month period ended December 31, 2010, total PUDs increased by 117 MMBoe to 937 MMBoe. EOG added approximately 37 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on page F-34 of this Annual Report on Form 10-K), EOG added 218 MMBoe. The proved undeveloped reserve additions were primarily in the Eagle Ford, Bakken, Barnett Combo and Haynesville shale plays, and nearly 73% of the additions were crude oil and condensate and natural gas liquids. During 2010, EOG drilled and transferred 118 MMBoe of PUDs to proved developed reserves at a total capital cost of $1,280 million. Revisions of PUDs totaled negative 12 MMBoe, primarily due to removal of certain natural gas PUDs from the five-year drilling plan. During 2010, EOG sold 8 MMBoe of PUDs.

For the twelve-month period ended December 31, 2009, total PUDs increased by 474 MMBoe to 820 MMBoe. Based on the definition of PUDs and its applicability to large resource plays (see discussion of technology employed on page F-34 of this Annual Report on Form 10-K), EOG added 445 MMBoe of PUDs, primarily in the Haynesville, Horn River, Barnett Combo and Marcellus shale plays. Purchases in place included 70 MMBoe of PUDs from the Rocky Mountain property exchange and the acquisition of Barnett Combo assets (see Note 16 to Consolidated Financial Statements). During 2009, EOG drilled and transferred approximately 29 MMBoe of PUDs to proved developed reserves at a total capital cost of $280 million. Revisions of PUDs totaled negative 9 MMBoe.

As of December 31, 2011, EOG did not have a material amount of reserves that have remained undeveloped for five years or more.

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's crude oil and natural gas producing activities at December 31, 2011 and 2010:

	2011	2010
Proved properties	$ 32,353,380	$ 27,693,700
Unproved properties	1,311,055	1,570,109
Total	33,664,435	29,263,809
Accumulated depreciation, depletion and amortization	(13,981,143)	(11,859,870)
Net capitalized costs	**$ 19,683,292**	**$ 17,403,939**

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 the Extractive Industries - Oil and Gas Topic of the ASC.

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.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2011, 2010 and 2009:

	United States	Canada	Trinidad	Other International (1)	Total
2011					
Acquisition Costs of Properties					
Unproved	$ 295,160	$ 6,216	$ -	$ (604)	$ 300,772
Proved	4,219	28	-	-	4,247
Subtotal	299,379	6,244	-	(604)	305,019
Exploration Costs	311,369	31,472	2,549	18,164	363,554
Development Costs (2)	5,410,378	302,564	138,905	78,744	5,930,591
Total	$ 6,021,126	$ 340,280	$ 141,454	$ 96,304	$ 6,599,164
2010					
Acquisition Costs of Properties					
Unproved	$ 403,509	$ 13,956	$ -	$ (107)	$ 417,358
Proved	-	-	-	-	-
Subtotal	403,509	13,956	-	(107)	417,358
Exploration Costs	454,379	38,604	23,386	86,784	603,153
Development Costs (3)	3,892,403	417,176	114,986	13,429	4,437,994
Total	$ 4,750,291	$ 469,736	$ 138,372	$ 100,106	$ 5,458,505
2009					
Acquisition Costs of Properties					
Unproved	$ 648,331	$ 17,806	$ 800	$ (311)	$ 666,626
Proved (4)	464,362	(33)	-	-	464,329
Subtotal	1,112,693	17,773	800	(311)	1,130,955
Exploration Costs	473,489	51,164	14,263	71,872	610,788
Development Costs (5)	1,898,859	237,613	27,369	1,914	2,165,755
Total	$ 3,485,041	$ 306,550	$ 42,432	$ 73,475	$ 3,907,498

(1) Other International primarily consists of EOG's United Kingdom and China operations.
(2) Includes Asset Retirement Costs of $52 million, $70 million, $7 million and $4 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(3) Includes Asset Retirement Costs of $71 million, $2 million, $(3) million and $2 million for the United States, Canada, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(4) Includes non-cash acquisition costs of $353 million related to a property exchange transaction in the Rocky Mountain area.
(5) Includes Asset Retirement Costs of $60 million, $18 million, $6 million and zero 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, 2011, 2010 and 2009:

	United States	Canada	Trinidad	Other International [(2)]	Total
2011					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 5,814,942	$ 459,853	$ 555,143	$ 28,250	$ 6,858,188
Other	32,329	258	586	-	33,173
Total	5,847,271	460,111	555,729	28,250	6,891,361
Exploration Costs	148,199	10,479	2,520	10,460	171,658
Dry Hole Costs	30,521	432	-	22,277	53,230
Transportation Costs	421,060	5,969	1,620	1,673	430,322
Production Costs	1,096,955	174,973	49,318	10,964	1,332,210
Impairments	575,976	452,103	-	2,958	1,031,037
Depreciation, Depletion and Amortization	2,011,080	258,772	106,802	17,160	2,393,814
Income (Loss) Before Income Taxes	1,563,480	(442,617)	395,469	(37,242)	1,479,090
Income Tax Provision (Benefit)	569,153	(121,044)	202,815	(13,056)	637,868
Results of Operations	$ 994,327	$ (321,573)	$ 192,654	$ (24,186)	$ 841,222
2010					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 3,928,240	$ 477,416	$ 447,852	$ 27,707	$ 4,881,215
Other	19,886	(31)	3,696	-	23,551
Total	3,948,126	477,385	451,548	27,707	4,904,766
Exploration Costs	156,252	17,597	2,277	11,255	187,381
Dry Hole Costs	30,927	14,875	5,000	21,684	72,486
Transportation Costs	372,466	9,892	1,348	1,483	385,189
Production Costs	763,769	174,667	51,125	8,504	998,065
Impairments	271,466	451,703	1,465	418	725,052
Depreciation, Depletion and Amortization	1,430,408	314,663	70,553	15,399	1,831,023
Income (Loss) Before Income Taxes	922,838	(506,012)	319,780	(31,036)	705,570
Income Tax Provision (Benefit)	375,855	(151,315)	140,413	(14,245)	350,708
Results of Operations	$ 546,983	$ (354,697)	$ 179,367	$ (16,791)	$ 354,862
2009					
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 2,732,088	$ 413,910	$ 229,649	$ 23,826	$ 3,399,473
Other	9,692	(15)	3,500	-	13,177
Total	2,741,780	413,895	233,149	23,826	3,412,650
Exploration Costs	137,696	18,675	5,107	8,114	169,592
Dry Hole Costs	39,570	1,461	-	10,212	51,243
Transportation Costs	270,940	9,317	1,141	1,931	283,329
Production Costs	556,236	145,292	27,616	9,452	738,596
Impairments	272,195	32,996	-	641	305,832
Depreciation, Depletion and Amortization	1,188,243	210,509	46,608	7,966	1,453,326
Income (Loss) Before Income Taxes	276,900	(4,355)	152,677	(14,490)	410,732
Income Tax Provision (Benefit)	106,537	(1,276)	58,681	(6,067)	157,875
Results of Operations	$ 170,363	$ (3,079)	$ 93,996	$ (8,423)	$ 252,857

(1) Excludes gains or losses on the mark-to-market of 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, 2011.

(2) Other International primarily consists of EOG's United Kingdom and China operations.

The following table sets forth production costs per barrel of oil equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2011, 2010 and 2009:

	United States	Canada	Trinidad	Other International [(1)]	Composite
Year Ended December 31, 2011	$ 6.19	$ 14.26	$ 0.78	$ 13.82	$ 6.03
Year Ended December 31, 2010	$ 5.00	$ 10.28	$ 0.65	$ 9.34	$ 4.85
Year Ended December 31, 2009	$ 4.43	$ 8.41	$ 0.74	$ 10.52	$ 4.40

(1) Other International primarily consists of EOG's United Kingdom and 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 the Extractive Industries - Oil and Gas Topic of the ASC and based on crude oil, natural gas liquids and natural gas reserves and production volumes estimated by the Engineering and Acquisitions Department of EOG. The estimates were based on a 12-month average for commodity prices for the years 2011, 2010 and 2009. The following information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

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

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible 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.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's oil and gas reserves for the years ended December 31, 2011, 2010 and 2009:

	United States	Canada	Trinidad	Other International [1]	Total
2011					
Future cash inflows [2]	$ 84,518,638	$ 5,056,501	$ 2,851,545	$ 103,853	$ 92,530,537
Future production costs	(33,294,343)	(2,315,110)	(388,199)	(62,938)	(36,060,590)
Future development costs	(13,811,449)	(1,566,917)	(149,884)	(331)	(15,528,581)
Future income taxes	(10,539,182)	(81,590)	(794,856)	(2,457)	(11,418,085)
Future net cash flows	26,873,664	1,092,884	1,518,606	38,127	29,523,281
Discount to present value at 10% annual rate	(12,498,010)	(456,537)	(334,399)	(9,054)	(13,298,000)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 14,375,654	$ 636,347	$ 1,184,207	$ 29,073	$ 16,225,281
2010					
Future cash inflows [3]	$ 62,063,123	$ 6,040,422	$ 2,760,819	$ 91,805	$ 70,956,169
Future production costs	(22,616,039)	(2,711,415)	(384,147)	(48,953)	(25,760,554)
Future development costs	(9,596,005)	(1,716,734)	(198,072)	(334)	(11,511,145)
Future income taxes	(8,503,301)	(129,816)	(850,699)	(3,598)	(9,487,414)
Future net cash flows	21,347,778	1,482,457	1,327,901	38,920	24,197,056
Discount to present value at 10% annual rate	(10,718,854)	(736,222)	(339,035)	(11,121)	(11,805,232)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 10,628,924	$ 746,235	$ 988,866	$ 27,799	$ 12,391,824
2009					
Future cash inflows [4]	$ 34,506,336	$ 6,887,530	$ 2,133,778	$ 52,738	$ 43,580,382
Future production costs	(11,977,152)	(2,537,001)	(398,318)	(27,791)	(14,940,262)
Future development costs	(5,696,619)	(2,255,088)	(264,104)	(346)	(8,216,157)
Future income taxes	(5,307,041)	(249,986)	(525,873)	(4,276)	(6,087,176)
Future net cash flows	11,525,524	1,845,455	945,483	20,325	14,336,787
Discount to present value at 10% annual rate	(5,702,608)	(808,211)	(279,920)	(5,030)	(6,795,769)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 5,822,916	$ 1,037,244	$ 665,563	$ 15,295	$ 7,541,018

(1) Other International includes EOG's United Kingdom and China operations.

(2) Estimated crude oil prices used to calculate 2011 future cash inflows for the United States, Canada, Trinidad and Other International were $97.75, $90.70, $92.50 and $102.86, respectively. Estimated natural gas liquids prices used to calculate 2011 future cash inflows for the United States and Canada were $51.77 and $46.97, respectively. Estimated natural gas prices used to calculate 2011 future cash inflows for the United States, Canada, Trinidad and Other International were $4.03, $3.28, $3.37, and $5.07, respectively.

(3) Estimated crude oil prices used to calculate 2010 future cash inflows for the United States, Canada, Trinidad and Other International were $76.38, $72.59, $69.56 and $73.88, respectively. Estimated natural gas liquids prices used to calculate 2010 future cash inflows for the United States and Canada were $43.85 and $26.56, respectively. Estimated natural gas prices used to calculate 2010 future cash inflows for the United States, Canada, Trinidad and Other International were $4.36, $3.67, $2.94 and $5.02, respectively.

(4) Estimated crude oil prices used to calculate 2009 future cash inflows for the United States, Canada, Trinidad and Other International were $53.64, $56.85, $51.35 and $52.87, respectively. Estimated natural gas liquids prices used to calculate 2009 future cash inflows for the United States and Canada were $28.75 and $19.31, respectively. Estimated natural gas prices used to calculate 2009 future cash inflows for the United States, Canada, Trinidad and Other International were $3.43, $3.50, $1.88 and $3.92, respectively.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2011:

	United States	Canada	Trinidad	Other International	Total
December 31, 2008	$ 6,307,712	$ 1,751,152	$ 601,053	$ 19,984	$ 8,679,901
Sales and transfers of oil and gas produced, net of production costs	(1,904,912)	(259,301)	(200,892)	(12,443)	(2,377,548)
Net changes in prices and production costs	(1,482,778)	(902,629)	338,053	(13,868)	(2,061,222)
Extensions, discoveries, additions and improved recovery, net of related costs	1,702,471	259,305	-	-	1,961,776
Development costs incurred	344,500	14,200	-	-	358,700
Revisions of estimated development cost	595,875	68,883	(3,380)	4,555	665,933
Revisions of previous quantity estimates	(422,294)	(425,018)	(124,222)	1,016	(970,518)
Accretion of discount	829,631	199,330	84,521	3,232	1,116,714
Net change in income taxes	261,513	259,169	(105,766)	9,847	424,763
Purchases of reserves in place	209,130	-	-	-	209,130
Sales of reserves in place	(264,482)	(13,912)	-	-	(278,394)
Changes in timing and other	(353,450)	86,065	76,196	2,972	(188,217)
December 31, 2009	5,822,916	1,037,244	665,563	15,295	7,541,018
Sales and transfers of oil and gas produced, net of production costs	(2,792,005)	(292,857)	(395,379)	(17,720)	(3,497,961)
Net changes in prices and production costs	2,468,907	(559)	721,796	7,259	3,197,403
Extensions, discoveries, additions and improved recovery, net of related costs	4,319,659	75,162	183,453	-	4,578,274
Development costs incurred	864,700	175,100	67,300	-	1,107,100
Revisions of estimated development cost	(257,360)	260,290	(767)	9	2,172
Revisions of previous quantity estimates	(164,748)	(38,382)	(175,002)	4,006	(374,126)
Accretion of discount	755,001	102,022	101,549	1,778	960,350
Net change in income taxes	(1,171,384)	101,966	(258,354)	2,469	(1,325,303)
Purchases of reserves in place	265	-	-	-	265
Sales of reserves in place	(54,057)	(290,592)	-	-	(344,649)
Changes in timing and other	837,030	(383,159)	78,707	14,703	547,281
December 31, 2010	10,628,924	746,235	988,866	27,799	12,391,824
Sales and transfers of oil and gas produced, net of production costs	(4,296,926)	(278,910)	(504,205)	(15,614)	(5,095,655)
Net changes in prices and production costs	716,682	(57,545)	331,196	3,328	993,661
Extensions, discoveries, additions and improved recovery, net of related costs	6,223,552	22,591	102,548	-	6,348,691
Development costs incurred	1,422,500	48,200	74,800	-	1,545,500
Revisions of estimated development cost	(210,919)	64,001	(14,074)	2	(160,990)
Revisions of previous quantity estimates	(482,496)	(70,718)	(56,884)	801	(609,297)
Accretion of discount	1,352,740	62,725	159,715	2,782	1,577,962
Net change in income taxes	(1,049,641)	(118,988)	9,511	13	(1,159,105)
Purchases of reserves in place	5,241	-	-	-	5,241
Sales of reserves in place	(658,468)	-	-	-	(658,468)
Changes in timing and other	724,465	218,756	92,734	9,962	1,045,917
December 31, 2011	**$ 14,375,654**	**$ 636,347**	**$ 1,184,207**	**$ 29,073**	**$ 16,225,281**

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

Quarter Ended	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2011				
Net Operating Revenues	$ 1,897,106	$ 2,570,250	$ 2,885,744	$ 2,773,015
Operating Income	$ 272,451	$ 588,253	$ 950,030	$ 302,575
Income Before Income Taxes	$ 225,722	$ 543,224	$ 899,221	$ 241,632
Income Tax Provision	91,749	247,650	358,343	120,934
Net Income	$ 133,973	$ 295,574	$ 540,878	$ 120,698
Net Income Per Share (1)				
Basic	$ 0.52	$ 1.11	$ 2.03	$ 0.45
Diluted	$ 0.52	$ 1.10	$ 2.01	$ 0.45
Average Number of Common Shares				
Basic	255,200	265,830	266,053	266,277
Diluted	258,819	269,332	269,292	269,524
2010				
Net Operating Revenues	$ 1,370,693	$ 1,357,968	$ 1,582,075	$ 1,789,160
Operating Income (Loss)	$ 219,902	$ 140,501	$ (11,695)	$ 174,611
Income (Loss) Before Income Taxes	$ 197,157	$ 110,059	$ (38,813)	$ 139,573
Income Tax Provision	79,142	50,187	32,093	85,900
Net Income (Loss)	$ 118,015	$ 59,872	$ (70,906)	$ 53,673
Net Income (Loss) Per Share (1)				
Basic	$ 0.47	$ 0.24	$ (0.28)	$ 0.21
Diluted	$ 0.46	$ 0.24	$ (0.28)	$ 0.21
Average Number of Common Shares				
Basic	250,370	250,825	251,015	251,365
Diluted	253,869	254,503	251,015	254,721

(1) The sum of quarterly net income (loss) per share may not agree with total year net income (loss) per share 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, 2011, 2010 and 2009

(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
2011				
Allowance deducted from Accounts Receivable	$ 13,642	$ 778	$ 11,711 [(1)]	$ 2,709
2010				
Allowance deducted from Accounts Receivable	$ 13,228	$ 885	$ 471	$ 13,642
2009				
Allowance deducted from Accounts Receivable	$ 13,131	$ 145	$ 48	$ 13,228

(1) Primarily reflects amounts related to bankruptcies which occurred in December 2001.

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 United States Securities and Exchange Commission (SEC) upon request.

Exhibit Number		Description
3.1(a)	-	Restated Certificate of Incorporation, dated September 3, 1987 (Exhibit 3.1(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
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, SEC 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, SEC 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, SEC 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, SEC 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, SEC File No. 001-09743, 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, SEC 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, SEC 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) (SEC File No. 001-09743).
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, 2007).
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) (SEC File No. 001-09743).
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).
3.2	-	Bylaws, as amended and restated effective as of February 26, 2009 (Exhibit 3.2(a) to EOG's Current Report on Form 8-K, filed March 4, 2009).
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).

Exhibit Number		Description
4.2	-	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, SEC File No. 33-42640, filed September 6, 1991).
4.3(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).
4.3(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).
4.3(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).
4.4(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).
4.4(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).
#4.5(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.
#4.5(b)	-	Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
#4.6(a)	-	Indenture, dated as of November 15, 2001, between EOG Company of Canada, as Issuer, and Wells Fargo Bank, National Association, as successor Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.6(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 Wells Fargo Bank, National Association, as successor Trustee, with respect to the 7.00% Senior Notes due 2011 of EOG Company of Canada.
#4.7	-	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.
4.8	-	Indenture, dated as of May 18, 2009, between EOG and Wells Fargo Bank, NA, as Trustee (Exhibit 4.9 to EOG's Registration Statement on Form S-3, SEC File No. 333-159301, filed May 18, 2009).
4.9(a)	-	Officers' Certificate Establishing 5.625% Senior Notes due 2019 of EOG, dated May 21, 2009 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 21, 2009).
4.9(b)	-	Form of Global Note with respect to the 5.625% Senior Notes due 2019 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 21, 2009).
4.10(a)	-	Officers’ Certificate Establishing 2.95% Senior Notes due 2015 and 4.40% Senior Notes due 2020, dated May 20, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 26, 2010).
4.10(b)	-	Form of Global Note with respect to the 2.95% Senior Notes due 2015 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 26, 2010).

Exhibit **Number**		**Description**
4.10(c)	-	Form of Global Note with respect to the 4.40% Senior Notes due 2020 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed May 26, 2010).
4.11(a)	-	Officers' Certificate Establishing 2.500% Senior Notes due 2016, 4.100% Senior Notes due 2021 and Floating Rate Senior Notes due 2014, dated November 23, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(b)	-	Form of Global Note with respect to the 2.500% Senior Notes due 2016 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(c)	-	Form of Global Note with respect to the 4.100% Senior Notes due 2021 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed November 24, 2010).
4.11(d)	-	Form of Global Note with respect to the Floating Rate Senior Notes due 2014 of EOG (Exhibit 4.5 to EOG's Current Report on Form 8-K, filed November 24, 2010).
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)+	-	Second Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of January 1, 2010 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.1(d)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made prior to February 23, 2011) (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(e)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made on or after February 23, 2011) (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.1(f)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made prior to February 23, 2011) (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed May 14, 2008).
10.1(g)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made on or after February 23, 2011) (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.1(h)	-	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(i)+	-	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(j)+	-	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).

Exhibit Number		Description
10.1(k)	-	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).
10.2(a)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Plan Document, effective as of December 16, 2008 (Exhibit 10.2(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008).
*10.2(b)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Adoption Agreement, originally dated as of December 16, 2008 (and as amended through February 24, 2012 (including an amendment to Item 7 thereof, effective January 1, 2012, with respect to the deferral of restricted stock units)) (originally filed as Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 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, SEC 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, SEC 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) (SEC File No. 001-09743).
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) (SEC File No. 001-09743).
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).

Exhibit Number		Description
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) (SEC File No. 001-09743).
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) (SEC File No. 001-09743).
10.6(b)+	-	First Amendment to Executive Employment Agreement between EOG and Mark G. Papa, effective as of March 16, 2009 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.6(c)+	-	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) (SEC File No. 001-09743).
10.6(d)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of April 30, 2009 (Exhibit 10.1(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.6(e)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of September 13, 2011 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed September 13, 2011).
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) (SEC File No. 001-09743).
10.7(b)+	-	First Amendment to Executive Employment Agreement between EOG and Loren M. Leiker, effective as of March 16, 2009 (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.7(c)+	-	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) (SEC File No. 001-09743).
10.7(d)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Loren M. Leiker, effective as of April 30, 2009 (Exhibit 10.2(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
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) (SEC File No. 001-09743).
10.8(b)+	-	First Amendment to Executive Employment Agreement between EOG and Gary L. Thomas, effective as of March 16, 2009 (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed March 18, 2009).
10.8(c)+	-	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) (SEC File No. 001-09743).
10.8(d)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of April 30, 2009 (Exhibit 10.3(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.8(e)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 13, 2011 (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed September 13, 2011).

Exhibit Number		**Description**
10.9(a)+	-	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) (SEC File No. 001-09743).
10.9(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of April 30, 2009 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.9(c)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of September 13, 2011 (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 13, 2011).
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)+	-	First Amendment to Executive Employment Agreement between EOG and Frederick J. Plaeger, II, effective as of April 30, 2009 (Exhibit 10.4(a) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.10(c)+	-	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).
10.10(d)+	-	First Amendment to Change of Control Agreement between EOG and Frederick J. Plaeger, II, effective as of April 30, 2009 (Exhibit 10.4(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.10(e)+	-	Second Amendment to Change of Control Agreement between EOG and Frederick J. Plaeger, II, effective as of September 13, 2011 (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed September 13, 2011).
10.11(a)+	-	Executive Employment Agreement between EOG and William R. Thomas, effective as of February 1, 2011 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.11(b)+	-	Change of Control Agreement between EOG and William R. Thomas, effective as of January 12, 2011 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.11(c)+	-	First Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 13, 2011 (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed September 13, 2011).
10.12(a)+	-	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) (SEC File No. 001-09743).
10.12(b)+	-	First Amendment to the EOG Resources, Inc. Change of Control Severance Plan, effective as of April 30, 2009 (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.13+	-	EOG Resources, Inc. Amended and Restated Executive Officer Annual Bonus Plan (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.14(a)+	-	EOG Resources, Inc. Employee Stock Purchase Plan (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-62256, filed June 4, 2001).
10.14(b)+	-	Amendment to EOG Resources, Inc. Employee Stock Purchase Plan, dated effective as of January 1, 2010 (Exhibit 4.3(b) to EOG's Registration Statement on Form S-8, SEC File No. 333-166518, filed May 4, 2010).

Exhibit Number		Description
10.15	-	Revolving Credit Agreement, dated as of October 11, 2011, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed October 12, 2011).
10.16	-	Revolving Credit Agreement, dated as of September 10, 2010, among EOG, Bank of America, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed September 14, 2010).
* 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, 2011.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Opinion of DeGolyer and MacNaughton dated February 1, 2012.
* 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.
* 95	-	Mine Safety Disclosure Exhibit.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income for Each of the Three Years in the Period Ended December 31, 2011, (ii) the Consolidated Balance Sheets - December 31, 2011 and 2010, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2011, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2011 and (v) Notes to Consolidated Financial Statements.

+ Management contract, compensatory plan or arrangement

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 24, 2012

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized 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 24th day of February, 2012.

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 Officer)
/s/ ANN D. JANSSEN (Ann D. Janssen)	Vice President, Accounting (Principal Accounting Officer)
* (George A. Alcorn)	Director
* (Charles R. Crisp)	Director
* (James C. Day)	Director
* (H. Leighton Steward)	Director
* (Donald F. Textor)	Director
* (Frank G. Wisner)	Director

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