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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 16, 2012

EOG RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Delaware	**1-9743**	**47-0684736**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1111 Bagby, Sky Lobby 2
Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

EOG RESOURCES, INC.

Item 2.02 Results of Operations and Financial Condition.

On February 16, 2012, EOG Resources, Inc. issued a press release announcing fourth quarter 2011 financial and operational results and first quarter and full year 2012 forecast and benchmark commodity pricing information (see Item 7.01 below). A copy of this release is attached as Exhibit 99.1 to this filing and is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended.

Item 7.01 Regulation FD Disclosure.

Accompanying the press release announcing fourth quarter 2011 financial and operational results attached hereto as Exhibit 99.1 is first quarter and full year 2012 forecast and benchmark commodity pricing information for EOG Resources, Inc., which information is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

99.1 Press Release of EOG Resources, Inc. dated February 16, 2012 (including the accompanying first quarter and full year 2012 forecast and benchmark commodity pricing information).

SIGNATURES

Pursuant to the requirements 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 hereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: February 16, 2012

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

EXHIBIT INDEX

Exhibit No.	**Description**
99.1	Press Release of EOG Resources, Inc. dated February 16, 2012 (including the accompanying first quarter and full year 2012 forecast and benchmark commodity pricing information).

EXHIBIT 99.1

EOG Resources, Inc. P.O. Box 4362 Houston, TX 77210-4362

News Release

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EOG Resources Reports 2011 Results, Increases Eagle Ford Reserve Potential and Increases Dividend

- Achieves 9.4 Percent Year-Over-Year Total Company Production Growth
- Reports 52 Percent North American Annual Crude Oil, Condensate and Natural Gas Liquids Growth with 48 Percent Increase in Total Company Liquids Volumes Year-Over-Year
- Delivers Strong Year-Over-Year Growth in EPS, EBITDAX and Discretionary Cash Flow
- Increases Eagle Ford Potential Recoverable Reserve Estimate by 78 Percent – from 900 MMboe to 1,600 MMboe, Net After Royalty
- Realizes Continued Drilling Success in Permian Basin Wolfcamp and Leonard Shale
- Raises Total Company Proved Reserves 5.3 Percent at Attractive Finding Costs
- Increases 2012 Total Company Organic Liquids Growth Target from 27 Percent to 30 Percent
- Raises Dividend on Common Stock for 13th Time in 13 Years

FOR IMMEDIATE RELEASE: Thursday, February 16, 2012

HOUSTON – EOG Resources, Inc. (EOG) today reported fourth quarter 2011 net income of $120.7 million, or $0.45 per share. This compares to fourth quarter 2010 net income of $53.7 million, or $0.21 per share. For the full year 2011, EOG reported net income of $1,091.1 million, or $4.10 per share, as compared to $160.7 million, or $0.63 per share, for the full year 2010.

Consistent with some analysts' practice of matching realizations to settlement months, and making certain other adjustments in order to exclude one-time items, adjusted non-GAAP net income for the quarter was $309.0 million, or $1.15 per share. Adjusted non-GAAP net income for the fourth quarter 2010 was $92.0 million, or $0.36 per share. The results for the fourth quarter 2011 included a $249.1 million, net of tax ($0.93 per share) impairment of certain North American non-core natural gas assets, gains on asset dispositions of $33.3 million, net of tax ($0.12 per share), the write-off of fees associated with revolving credit facilities of $3.7 million, net of tax ($0.01 per share) and a previously disclosed non-cash net gain of $145.5 million ($93.2 million after tax, or $0.35 per share) on the mark-to-market of financial commodity contracts. During the quarter, the net cash inflow related to financial commodity contracts was $96.9 million ($62.0 million after tax, or $0.23 per share).

On a similar basis, eliminating the items detailed in the attached table, adjusted non-GAAP net income for the full year 2011 was $1,008.5 million, or $3.79 per share, and for the full year 2010 was $296.4 million, or $1.16 per share. (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income to GAAP net income.)

"EOG had an exceptional year in 2011 with a 551 percent increase in earnings per share versus 2010. This solidifies the completion of our goal of becoming an oil company. These strong returns are one of the traditional hallmarks of EOG," said Mark G. Papa, Chairman and Chief Executive Officer.

Through its focus on higher margins and returns, EOG posted strong financial metrics year-over-year in adjusted non-GAAP earnings per share, adjusted EBITDAX and discretionary cash flow. Compared to 2010, adjusted non-GAAP earnings per share increased 227 percent, adjusted EBITDAX increased 55 percent and discretionary cash flow rose 52 percent. (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income per share to GAAP net income per share, adjusted EBITDAX (non-GAAP) to income before interest expense and income taxes (GAAP) and non-GAAP discretionary cash flow to net cash provided by operating activities (GAAP).)

2011 Operational Highlights

For the full year 2011, total company production increased 9.4 percent compared to 2010, driven by 52 percent organic growth in North American crude oil, condensate and natural gas liquids, and a 48 percent increase in total company liquids production. During the fourth quarter, United States crude oil and condensate production rose 68 percent compared to 2010, contributing to a 61 percent increase for the full year 2011.

Crude Oil and Liquids Activity

2011 marked a significant year in the development of EOG's single largest asset, the South Texas Eagle Ford. Production at year-end was 66 thousand barrels of oil equivalent per day, net, 78 percent of which was crude oil.

Starting 2011 with a 12-rig drilling program that ramped up to 26 rigs in December, EOG drilled and completed 244 net wells during the year with a focus on optimizing completion techniques, in addition to reducing drilling days and overall well costs. Moving into development mode early in 2011, EOG began shifting its attention to increasing recovery of the oil-in-place in the field. To test the impact of well spacing on reserve recoveries, EOG drilled eight pilot programs that included 33 total wells. Based on production analysis from these pilots and reservoir modeling, EOG is now pursuing development drilling on 65 to 90-acre spacing, significantly tighter than the original density of 130 acres between wells.

After taking into account both the excellent results from the 375 wells it has drilled to date across its 120-mile acreage position and the results from the down-spaced drilling tests, EOG has increased its estimated potential reserves in the Eagle Ford from 900 million barrels of oil equivalent (MMboe) to 1,600 MMboe, net after royalty (NAR). The 700 MMBoe, NAR, or 78 percent increase represents an estimated 6 percent recovery factor. On its 572,000 net acres in the prolific oil window, EOG has identified approximately 3,200 remaining drilling locations and increased its average per well estimate to 450 thousand barrels of oil equivalent (MBoe), NAR.

EOG's well results in the Eagle Ford continue to lead the industry. In Gonzales County, the Henkhaus Unit #1H, #2H, #3H, #4H, #6H and #7H wells were drilled on a pattern of 65-acre spacing. The six wells were completed to sales at individual initial production rates ranging from 2,424 to 3,733 barrels of oil per day (Bopd) with 442 to 679 barrels per day (Bpd) of natural gas liquids (NGLs) and 2.2 to 3.4 million cubic feet per day (MMcfd) of natural gas per well. The Mitchell Unit #3H, #4H, #5H, #6H, #7H and #8H wells, which were also drilled as down-spaced pilots, began initial production at 2,833 to 3,527 Bopd with 275 to 485 Bpd of NGLs and 1.4 to 2.4 MMcfd of natural gas per well. The Meyer #3H, #4H, #5H, #8H and #9H wells had individual peak oil rates ranging from 1,647 to 2,813 Bopd with 199 to 413 Bpd of NGLs and 1.0 to 2.1 MMcfd of natural gas. EOG has 100 percent working interest in these 17 Gonzales County wells.

"With tremendous resource potential still remaining on our acreage, we continue to test and apply techniques that will increase the oil recovery and potential of the Eagle Ford, our crown jewel. This strategy takes us into the next inning of development. By concentrating our efforts on getting more oil out of the ground early in the development phase, we are taking a good asset and making it great," Papa said. "Looking across the industry, we believe EOG's Eagle Ford position represents the largest domestic net oil discovery in 40 years and the highest rate of return play in North America today."

In the Fort Worth Barnett Shale Combo, EOG's second largest driver of liquids growth during 2011, total liquids production increased 107 percent compared to 2010, driven by a 124 percent increase in crude oil and condensate production. In Montague County, a pattern of five horizontal wells, the Badger A Unit #1H, B Unit #2H, C Unit #3H, D Unit #4H and E Unit #5H showed initial peak oil production rates ranging from 525 to 659 Bopd with 106 to 205 Bpd of NGLs and 704 to 1,361 Mcfd (thousand cubic feet per day) of natural gas per well. EOG has 100 percent working interest in the wells, which had an average peak crude oil production rate of 604 Bopd per well. A series of 10 McKown wells drilled in Cooke County, began producing to sales at an average oil rate of 689 Bopd, with 210 Bpd of NGLs and 1.4 MMcfd of natural gas per well. EOG has 93 percent working interest in these wells.

During 2011, EOG expanded its core holdings in the Barnett Combo by approximately 25,000 acres to 200,000 net acres. Following the success of its drilling program last year, EOG expects the Barnett Combo to be its second largest liquids production growth contributor again in 2012.

In the West Texas Permian Basin, EOG increased drilling activity in the Wolfcamp formation during the second half of 2011 in preparation for a more active year in 2012. EOG reported success from the upper Wolfcamp zone. The University 9 #2803H in Reagan County, 25 miles west of its current middle Wolfcamp activity began production at 883 Bopd with 68 Bpd of NGLs and 388 Mcfd of natural gas. EOG has a 100 percent working interest in the well. In Irion County, the University 43 #0902H and 40A #0402H were completed in the middle Wolfcamp zone at initial oil rates of 1,088 and 1,076 Bopd, respectively. In addition to the strong oil production, the wells were turned to sales with 86 and 129 Bpd of NGLs and 489 and 736 Mcfd of natural gas, respectively. EOG has 90 and 85 percent working interest in the wells, respectively. On the border between Irion and Crockett counties, the University 40 #1309H and 38 #0601H began production at 1,738 and 1,077 Bopd with 137 and 119 Bpd of NGLs and 779 and 678 Mcfd of natural gas, respectively. EOG has 88 percent working interest in these wells. EOG plans to operate a four-rig drilling program in the Wolfcamp during 2012.

In the New Mexico Leonard Shale, EOG reported drilling success from Lea County with the Caballo 23 Fed #4H and #6H. The wells, in which EOG has 86 percent working interest, initially produced at 932 and 750 Bopd with 116 and 99 Bpd of NGLs and 636 and 545 Mcfd of natural gas, respectively. During 2012, EOG is positioned to increase its drilling activity in the Leonard Shale with a year-long two-rig program.

Consistent with its game plan to increase recovery rates in existing fields, during 2011 EOG continued infill drilling on its core acreage in the North Dakota Bakken Parshall Field, which it discovered in 2006. Although originally developed on 640-acre spacing, EOG has successfully tested 320-acre down-spacing in various areas and around the perimeters of the field. A recent well in Mountrail County, the Fertile 48-0905H, in which EOG has a 96 percent working interest, was completed at an initial rate of 1,324 Bopd. Also in Mountrail County, the Liberty 24-2531H and Liberty LR 20-26H were drilled on 320-acre spacing. The wells, in which EOG has 82 and 95 percent working interest, respectively, were turned to sales at initial crude oil rates of 1,507 and 1,165 Bopd, respectively. Over the course of 2012, EOG will continue its efforts to increase recovery of the oil-in-place on its Bakken acreage through further down-spacing tests and the initiation of a secondary recovery pilot project.

Reserves

EOG's total company net proved reserves for 2011 increased 5.3 percent over the prior year from 1,950 to 2,054 MMBoe, all organic. Total liquids proved reserves increased 39 percent year-over-year. Excluding the impact of property dispositions, total company and total North American net proved developed reserves increased 8.8 percent and 8.2 percent, respectively. Total liquids proved reserves, as a percentage of total company proved reserves, increased from 28 percent to 36 percent.

In 2011:

- Total reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 167 percent at a total reserve replacement cost of $19.68 per barrel of oil equivalent (Boe), based on exploration and development expenditures of $6,466 million. (For the calculation of total reserve replacement and total reserve replacement costs, please refer to the attached tables.)
- Total liquids reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 465 percent. (For the calculation of total liquids reserve replacement, please refer to the attached tables.)

- Reserve replacement from drilling – the ratio of extensions, discoveries and other additions to total production – was 248 percent. (Pease refer to the attached tables.)
- In the United States, total reserve replacement from all sources was 216 percent at a reserve replacement cost of $18.00 per Boe based on exploration and development expenditures of $5,969 million. (For the calculation of U.S. total reserve replacement and total reserve replacement costs, please refer to the attached tables.) In the United States, 72 percent of the reserve additions were liquids.

For the 24th consecutive year, internal reserve estimates were within 5 percent of those prepared by the independent reserve engineering firm of DeGolyer and MacNaughton (D&M). For 2011, D&M prepared a complete independent engineering analysis of properties containing 85 percent of EOG's proved reserves on a Boe basis.

Natural Gas Activity

EOG is continuing to de-emphasize dry natural gas drilling activity on its Haynesville, Marcellus and Horn River acreage to pursue higher rate of return opportunities in its crude oil and liquids-rich unconventional resource plays. Since 2008, EOG's North American natural gas production has declined annually, with a 7 percent reduction from 2010 to 2011. Because EOG's outlook for natural gas prices is weak for the next several years, EOG plans to invest the minimum amount of capital expenditures necessary to hold its core acreage positions. During 2012, approximately 10 percent of EOG's exploration and development capital expenditures is expected to be allocated to dry natural gas drilling activity, a significant decrease from 2011.

Capital Structure

During 2011, total cash proceeds from asset sales were $1.43 billion. At December 31, 2011, EOG's total debt outstanding was $5,009 million for a debt-to-total capitalization ratio of 28 percent. Taking into account cash on the balance sheet of $616 million at year-end, EOG's net debt was $4,393 million for a net debt-to-total capitalization ratio of 26 percent. (Please refer to the attached tables for the reconciliation of net debt (non-GAAP) to current and long-term debt (GAAP) and the reconciliation of net debt-to-total capitalization ratio (non-GAAP) to debt-to-total capitalization ratio (GAAP).)

"EOG hit a series of home runs during 2011. We exceeded our crude oil production growth targets and increased the estimated reserves in the Eagle Ford by increasing individual per well reserves and improving the overall recovery factor in the field," Papa said. "The business model we set in motion several years ago is working, evidenced by the outstanding operational and financial metrics EOG achieved in 2011."

2012 Operational Plans and Targets

EOG is targeting total company production growth of 5.5 percent in 2012 and has increased its total organic liquids production growth forecast from the previously stated 27 percent to 30 percent. Total liquids growth is expected to be comprised of a 30 percent increase in crude oil and condensate production and a 30 percent increase in natural gas liquids production. In North America, natural gas production is expected to decrease 11 percent from 2011, reflecting additional producing property sales and a further de-emphasis on natural gas drilling in a weak price environment.

Estimated exploration and production expenditures for 2012 are expected to range from $7.4 to $7.6 billion, including exploration and development, production facilities and midstream expenditures. To offset any funding gap between estimated cash flows and capital expenditures, EOG expects to sell approximately $1.2 billion of assets during 2012, including crude oil, liquids-rich and natural gas producing properties, of which $340 million has closed to date. With a continued focus on the balance sheet in 2012, EOG plans to maintain a net debt-to-total capitalization ratio below 30 percent at year-end.

EOG has hedged approximately 23 percent of its North American crude oil production for 2012. For the period February 1 through June 30, 2012, EOG has crude oil financial price swap contracts in place for approximately 33 percent of its production at a weighted average price of $105.36 per barrel, excluding unexercised options. For the period July 1 through December 31, 2012, EOG has 14 percent of its production hedged at a weighted average price of $104.26 per barrel, excluding unexercised options.

For 2012, EOG has hedged approximately 45 percent of its North American natural gas production. For the period March 1 through December 31, 2012, EOG has natural gas financial price swap contracts in place for 525,000 million British thermal units per day (MMBtud) at a weighted average price of $5.44 per million British thermal units (MMBtu), excluding unexercised options. For each of the years 2013 and 2014, EOG has natural gas financial price swap contracts of 150,000 MMBtud in place at a weighted average price of $4.79 per MMBtu, excluding unexercised options. (For a comprehensive summary of crude oil and natural gas derivative contracts, please refer to the attached tables.)

Dividend Increase

Following an increase in the common stock dividend in 2011, EOG's Board of Directors has again increased the cash dividend on the common stock. Effective with the dividend payable on April 30, 2012, to holders of record as of April 16, 2012, the quarterly dividend on the common stock will be $0.17 per share, an increase of 6.25 percent over the previous indicated annual rate. The indicated annual rate of $0.68 per share reflects the 13th increase in 13 years.

Conference Call Scheduled for February 17, 2012

EOG's full year 2011 results conference call will be available via live audio webcast at 8 a.m. Central time (9 a.m. Eastern time) on Friday, February 17, 2012. To listen, log on to www.eogresources.com. The webcast will be archived on EOG's website through March 2, 2012.

EOG Resources, Inc. 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 Resources, Inc. is listed on the New York Stock Exchange and is traded under the ticker symbol "EOG."

This press release 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 or generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that 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, 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 and advanced completion technologies;
- 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 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 and hydraulic fracturing and laws and regulations imposing conditions and restrictions on drilling and completion operations;
- 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;
- 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 timing and impact of liquefied natural gas imports and exports;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors", on pages 14 through 20 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2010 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.

Effective January 1, 2010, the United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). As noted above, statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve estimates provided in this press release that are not specifically designated as being estimates of proved reserves may include "potential" reserves and/or other estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2010, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov.

EOG RESOURCES, INC.
FINANCIAL REPORT
(Unaudited; in millions, except per share data)

	Three Months Ended December 31, 2011	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2011	Twelve Months Ended December 31, 2010
Net Operating Revenues	$ 2,773.0	$ 1,789.2	$ 10,126.1	$ 6,099.9
Net Income	$ 120.7	$ 53.7	$ 1,091.1	$ 160.7
Net Income Per Share				
Basic	$ 0.45	$ 0.21	$ 4.15	$ 0.64
Diluted	$ 0.45	$ 0.21	$ 4.10	$ 0.63
Average Number of Common Shares				
Basic	266.3	251.4	262.7	250.9
Diluted	269.5	254.7	266.3	254.5

SUMMARY INCOME STATEMENTS
(Unaudited; in thousands, except per share data)

	Three Months Ended December 31, 2011	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2011	Twelve Months Ended December 31, 2010
Net Operating Revenues				
Crude Oil and Condensate	$ 1,189,250	$ 630,433	$ 3,838,284	$ 1,998,771
Natural Gas Liquids	240,260	147,595	779,364	462,345
Natural Gas	479,825	587,521	2,240,540	2,420,099
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	145,514	(43,904)	626,053	61,912
Gathering, Processing and Marketing	654,489	307,890	2,115,792	909,680
Gains on Asset Dispositions, Net	49,928	151,097	492,909	223,538
Other, Net	13,749	8,528	33,173	23,551
Total	2,773,015	1,789,160	10,126,115	6,099,896
Operating Expenses				
Lease and Well	261,244	190,783	941,954	698,430
Transportation Costs	122,046	98,871	430,322	385,189
Gathering and Processing Costs	25,283	19,405	80,727	66,758
Exploration Costs	31,042	38,746	171,658	187,381
Dry Hole Costs	5,999	27,391	53,230	72,486
Impairments	499,624	239,782	1,031,037	742,647
Marketing Costs	644,687	292,477	2,072,137	884,212
Depreciation, Depletion and Amortization	693,527	543,789	2,516,381	1,941,926
General and Administrative	85,108	74,004	304,811	280,474
Taxes Other Than Income	101,880	89,301	410,549	317,074
Total	2,470,440	1,614,549	8,012,806	5,576,577
Operating Income	302,575	174,611	2,113,309	523,319
Other Income (Expense), Net	(4,352)	6,333	6,853	14,243
Income Before Interest Expense and Income Taxes	298,223	180,944	2,120,162	537,562
Interest Expense, Net	56,591	41,371	210,363	129,586
Income Before Income Taxes	241,632	139,573	1,909,799	407,976
Income Tax Provision	120,934	85,900	818,676	247,322
Net Income	$ 120,698	$ 53,673	$ 1,091,123	$ 160,654
Dividends Declared per Common Share	$ 0.160	$ 0.155	$ 0.640	$ 0.620

EOG RESOURCES, INC.
OPERATING HIGHLIGHTS
(Unaudited)

	Three Months Ended December 31, 2011	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2011	Twelve Months Ended December 31, 2010
Wellhead Volumes and Prices				
Crude Oil and Condensate Volumes (MBbld) (A)				
United States	124.8	74.4	102.0	63.2
Canada	7.6	8.6	7.9	6.7
Trinidad	2.8	4.7	3.4	4.7
Other International (B)	0.1	0.1	0.1	0.1
Total	135.3	87.8	113.4	74.7
Average Crude Oil and Condensate Prices ($/Bbl) (C)				
United States	$ 96.33	$ 80.38	$ 92.92	$ 74.88
Canada	89.32	75.47	91.92	72.66
Trinidad	87.02	74.36	90.62	68.80
Other International (B)	103.46	74.29	100.11	73.11
Composite	95.75	79.55	92.79	74.29
Natural Gas Liquids Volumes (MBbld) (A)				
United States	49.6	35.7	41.5	29.5
Canada	1.1	0.8	0.9	0.9
Total	50.7	36.5	42.4	30.4
Average Natural Gas Liquids Prices ($/Bbl) (C)				
United States	$ 51.58	$ 43.95	$ 50.37	$ 41.68
Canada	49.16	44.98	52.69	43.40
Composite	51.53	43.97	50.41	41.73
Natural Gas Volumes (MMcfd) (A)				
United States	1,085	1,241	1,113	1,133
Canada	124	185	132	200
Trinidad	313	340	344	341
Other International (B)	11	12	13	14
Total	1,533	1,778	1,602	1,688
Average Natural Gas Prices ($/Mcf) (C)				
United States	$ 3.27	$ 3.78	$ 3.92	$ 4.30
Canada	3.14	3.30	3.71	3.91
Trinidad	3.87	2.99	3.53	2.65
Other International (B)	5.70	5.91	5.62	4.90
Composite	3.40	3.59	3.83	3.93
Crude Oil Equivalent Volumes (MBoed) (D)				
United States	355.3	317.0	329.1	281.5
Canada	29.3	40.3	30.7	40.9
Trinidad	54.9	61.3	60.7	61.5
Other International (B)	2.0	2.0	2.2	2.5
Total	441.5	420.6	422.7	386.4
Total MMBoe (D)	40.6	38.7	154.3	141.1

(A) Thousand barrels per day or million cubic feet per day, as applicable.
(B) Other International includes EOG's United Kingdom and China operations.
(C) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments.
(D) 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.

EOG RESOURCES, INC.
SUMMARY BALANCE SHEETS
(Unaudited; in thousands, except share data)

	December 31, 2011	December 31, 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		
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

EOG RESOURCES, INC.
SUMMARY STATEMENTS OF CASH FLOWS
(Unaudited; in thousands)

	Twelve Months Ended December 31, 2011	Twelve Months Ended December 31, 2010
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 1,091,123	$ 160,654
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	2,516,381	1,941,926
Impairments	1,031,037	742,647
Stock-Based Compensation Expenses	128,345	107,378
Deferred Income Taxes	499,300	76,245
Gains on Asset Dispositions, Net	(492,909)	(223,538)
Other, Net	15,139	(468)
Dry Hole Costs	53,230	72,486
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(626,053)	(61,912)
Realized Gains	180,701	7,033
Other, Net	26,454	17,273
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(339,780)	(339,126)
Inventories	(176,623)	(171,791)
Accounts Payable	351,087	654,688
Accrued Taxes Payable	92,589	(53,098)
Other Assets	(23,625)	(32,169)
Other Liabilities	14,986	19,342
Changes in Components of Working Capital Associated with Investing and Financing Activities	237,028	(208,968)
Net Cash Provided by Operating Activities	4,578,410	2,708,602
Investing Cash Flows		
Additions to Oil and Gas Properties	(6,294,397)	(5,210,612)
Additions to Other Property, Plant and Equipment	(656,415)	(370,770)
Acquisition of Galveston LNG Inc.	-	(210,000)
Proceeds from Sales of Assets	1,433,137	672,593
Changes in Components of Working Capital Associated with Investing Activities	(237,267)	208,933
Other, Net	-	7,082
Net Cash Used in Investing Activities	(5,754,942)	(4,902,774)
Financing Cash Flows		
Common Stock Sold	1,388,265	-
Long-term Debt Borrowings	-	2,478,659
Long-term Debt Repayments	(220,000)	(37,000)
Dividends Paid	(167,169)	(153,240)
Treasury Stock Purchased	(23,922)	(11,295)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	35,913	34,560
Debt Issuance Costs	(4,787)	(8,300)
Other, Net	239	35
Net Cash Provided by Financing Activities	1,008,539	2,303,419
Effect of Exchange Rate Changes on Cash	(5,134)	(6,145)
(Decrease) Increase in Cash and Cash Equivalents	(173,127)	103,102
Cash and Cash Equivalents at Beginning of Period	788,853	685,751
Cash and Cash Equivalents at End of Period	$ 615,726	$ 788,853

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF ADJUSTED NET INCOME (NON-GAAP) TO NET INCOME (GAAP)
(Unaudited; in thousands, except per share data)

The following chart adjusts the three-month and twelve-month periods ended December 31, 2011 and 2010 reported Net Income (GAAP) to reflect actual net cash realized from financial commodity derivative transactions by eliminating the unrealized mark-to-market (gains) losses from these transactions, to add back impairment charges related to certain of EOG's North American assets in 2011 and in 2010, to add back the write-off of fees associated with revolving credit facilities cancelled in connection with the establishment of a new revolving credit facility in the fourth quarter of 2011, to eliminate the net gains on asset dispositions primarily in North America in 2011 and 2010, and to eliminate the change in the estimated fair value of a contingent consideration liability in 2010 related to EOG's previously disclosed acquisition of Haynesville and Bossier Shale unproved acreage. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported company earnings to match realizations to production settlement months and make certain other adjustments to exclude non-recurring items. EOG management uses this information for comparative purposes within the industry.

	Three Months Ended December 31,		Twelve Months Ended December 31,		
	2011	**2010**	**2011**	**2010**	
Reported Net Income (GAAP)	$ 120,698	$ 53,673	$ 1,091,123	$ 160,654	
Mark-to-Market (MTM) Commodity Derivative Contracts Impact					
Total (Gains) Losses	(145,514)	43,904	(626,053)	(61,912)	
Realized Gains (Losses)	96,936	(18,147)	180,701	7,033	
Subtotal	(48,578)	25,757	(445,352)	(54,879)	
After-Tax MTM Impact	(31,101)	16,424	(285,136)	(35,203)	
Add: Impairment of Certain North American Assets, Net of Tax	249,084	122,344	516,198	330,675	
Add: Write-off of Fees Associated with Revolving Credit Facilities, Net of Tax	3,656	-	3,656	-	
Less: Net Gains on Asset Dispositions, Net of Tax	(33,337)	(98,835)	(317,342)	(145,216)	
Less: Change in Fair Value of Contingent Consideration Liability, Net of Tax	-	(1,580)	-	(14,521)	
Adjusted Net Income (Non-GAAP)	$ 309,000	$ 92,026	$ 1,008,499	$ 296,389	
Net Income Per Share (GAAP)					
Basic	$ 0.45	$ 0.21	$ 4.15	$ 0.64	
Diluted	$ 0.45	$ 0.21	$ 4.10 **(a)**	$ 0.63	**(b)**
Percentage Increase - [(a) - (b)] / (b)			**551%**		
Adjusted Net Income Per Share (Non-GAAP)					
Basic	$ 1.16	$ 0.37	$ 3.84	$ 1.18	
Diluted	$ 1.15	$ 0.36	$ 3.79 **(c)**	$ 1.16	**(d)**
Percentage Increase - [(c) - (d)] / (d)			**227%**		
Average Number of Common Shares					
Basic	266,277	251,365	262,735	250,876	
Diluted	269,524	254,716	266,268	254,500	

EOG RESOURCES, INC.

QUANTITATIVE RECONCILIATION OF ADJUSTED EARNINGS BEFORE INTEREST EXPENSE, INCOME TAXES, DEPRECIATION, DEPLETION AND AMORTIZATION, EXPLORATION COSTS, DRY HOLE COSTS AND IMPAIRMENTS (ADJUSTED EBITDAX) (NON-GAAP) TO INCOME BEFORE INTEREST EXPENSE AND INCOME TAXES (GAAP)

(Unaudited; in thousands)

The following chart adjusts the twelve-month period ended December 31, 2011 and 2010 reported Income Before Interest Expense and Income Taxes (GAAP) to Earnings Before Interest Expense, Income Taxes, Depreciation, Depletion and Amortization, Exploration Costs, Dry Hole Costs and Impairments (EBITDAX) (Non-GAAP) and to further adjust to reflect actual net cash realized from financial commodity derivative transactions by eliminating the unrealized mark-to-market (MTM) gains from these transactions and to eliminate the net gains on asset dispositions primarily in North America in 2011 and 2010. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported Income Before Interest Expense and Income Taxes (GAAP) to add back Depreciation, Depletion and Amortization, Exploration Costs, Dry Hole Costs and Impairments and further adjust to match realizations to production settlement months and make certain other adjustments to exclude non-recurring items. EOG management uses this information for comparative purposes within the industry.

	Twelve Months Ended December 31, 2011		Twelve Months Ended December 31, 2010	
Income Before Interest Expense and Income Taxes (GAAP)	$ 2,120,162		$ 537,562	
Adjustments:				
Depreciation, Depletion and Amortization	2,516,381		1,941,926	
Exploration Costs	171,658		187,381	
Dry Hole Costs	53,230		72,486	
Impairments	1,031,037		742,647	
EBITDAX (Non-GAAP)	5,892,468		3,482,002	
Total Gains on MTM Commodity Derivative Contracts	(626,053)		(61,912)	
Realized Gains on MTM Commodity Derivative Contracts	180,701		7,033	
Net Gains on Asset Dispositions	(492,909)		(223,538)	
Adjusted EBITDAX (Non-GAAP)	$ 4,954,207	**(a)**	$ 3,203,585	**(b)**
Percentage Increase - [(a) - (b)] / (b)	**55%**			

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF DISCRETIONARY CASH FLOW (NON-GAAP)
TO NET CASH PROVIDED BY OPERATING ACTIVITIES (GAAP)
(Unaudited; in thousands)

The following chart reconciles the three-month and twelve-month periods ended December 31, 2011 and 2010 Net Cash Provided by Operating Activities (GAAP) to Discretionary Cash Flow (Non-GAAP). EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust Net Cash Provided by Operating Activities for Exploration Costs (excluding Stock-Based Compensation Expenses), Changes in Components of Working Capital and Other Assets and Liabilities, and Changes in Components of Working Capital Associated with Investing and Financing Activities. EOG management uses this information for comparative purposes within the industry.

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2011	**2010**	**2011**	**2010**
Net Cash Provided by Operating Activities (GAAP)	$ 1,236,887	$ 622,875	$ 4,578,410	$ 2,708,602
Adjustments				
Exploration Costs (excluding Stock-Based Compensation Expenses)	24,715	32,676	145,881	163,274
Changes in Components of Working Capital and Other Assets and Liabilities				
Accounts Receivable	210,815	214,313	339,780	339,126
Inventories	9,012	37,610	176,623	171,791
Accounts Payable	(105,702)	(127,270)	(351,087)	(654,688)
Accrued Taxes Payable	8,650	12,994	(92,589)	53,098
Other Assets	(4,975)	16,118	23,625	32,169
Other Liabilities	22,036	25,006	(14,986)	(19,342)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(103,801)	(7,727)	(237,028)	208,968
Discretionary Cash Flow (Non-GAAP)	$ 1,297,637	$ 826,595	$ 4,568,629 **(a)**	$ 3,002,998 **(b)**
Percentage Increase - [(a) - (b)] / (b)			**52%**	

EOG RESOURCES, INC.
RESERVES SUPPLEMENTAL DATA
(Unaudited)

2011 NET PROVED RESERVES RECONCILIATION SUMMARY

CRUDE OIL & CONDENSATE (MMBbls)	**United States**	**Canada**	**North America**	**Trinidad**	**Other Int'l**	**Total Int'l**	**Total**
Beginning Reserves	355.5	25.6	381.1	4.7	0.1	4.8	385.9
Revisions	(21.2)	(4.6)	(25.8)	0.1	-	0.1	(25.7)
Purchases in place	-	-	-	-	-	-	-
Extensions, discoveries and other additions	202.5	0.5	203.0	-	-	-	203.0
Sales in place	(4.3)	-	(4.3)	-	-	-	(4.3)
Production	(37.2)	(2.9)	(40.1)	(1.3)	-	(1.3)	(41.4)
Ending Reserves	**495.3**	**18.6**	**513.9**	**3.5**	**0.1**	**3.6**	**517.5**
NATURAL GAS LIQUIDS (MMBbls)							
Beginning Reserves	150.4	1.5	151.9	-	-	-	151.9
Revisions	36.1	-	36.1	-	-	-	36.1
Purchases in place	-	-	-	-	-	-	-
Extensions, discoveries and other additions	65.3	-	65.3	-	-	-	65.3
Sales in place	(10.0)	-	(10.0)	-	-	-	(10.0)
Production	(15.2)	(0.3)	(15.5)	-	-	-	(15.5)
Ending Reserves	**226.6**	**1.2**	**227.8**	-	-	-	**227.8**
NATURAL GAS (Bcf)							
Beginning Reserves	6,491.5	1,133.8	7,625.3	827.6	17.3	844.9	8,470.2
Revisions	(344.0)	(49.8)	(393.8)	(24.2)	1.3	(22.9)	(416.7)
Purchases in place	3.0	-	3.0	-	-	-	3.0
Extensions, discoveries and other additions	634.6	-	634.6	74.7	4.5	79.2	713.8
Sales in place	(323.6)	-	(323.6)	-	-	-	(323.6)
Production	(415.7)	(48.1)	(463.8)	(127.4)	(4.6)	(132.0)	(595.8)
Ending Reserves	**6,045.8**	**1,035.9**	**7,081.7**	**750.7**	**18.5**	**769.2**	**7,850.9**
OIL EQUIVALENTS (MMBoe)							
Beginning Reserves	1,587.8	216.1	1,803.9	142.7	2.9	145.6	1,949.5
Revisions	(42.5)	(12.9)	(55.4)	(4.0)	0.2	(3.8)	(59.2)
Purchases in place	0.5	-	0.5	-	-	-	0.5
Extensions, discoveries and other additions	373.6	0.5	374.1	12.4	0.8	13.2	387.3
Sales in place	(68.2)	-	(68.2)	-	-	-	(68.2)
Production	(121.7)	(11.2)	(132.9)	(22.5)	(0.7)	(23.2)	(156.1)
Ending Reserves	**1,729.5**	**192.5**	**1,922.0**	**128.6**	**3.2**	**131.8**	**2,053.8**
Net Proved Developed Reserves (MMBoe)							
At December 31, 2010	**839.9**	**79.7**	**919.6**	**90.4**	**3.0**	**93.4**	**1,013.0**
At December 31, 2011	**877.3**	**58.5**	**935.8**	**103.7**	**3.2**	**106.9**	**1,042.7**

EOG RESOURCES, INC.
RESERVES SUPPLEMENTAL DATA (CONTINUED)
(Unaudited)

2011 EXPLORATION AND DEVELOPMENT EXPENDITURES ($ Millions)

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
Acquisition Cost of Unproved Properties	$ 295.2	$ 6.2	$ 301.4	$ -	$ (0.6)	$ (0.6)	$ 300.8
Exploration Costs	311.3	31.5	342.8	2.6	18.1	20.7	363.5
Development Costs	5,358.6	232.8	5,591.4	132.1	74.0	206.1	5,797.5
Total Drilling	**5,965.1**	**270.5**	**6,235.6**	**134.7**	**91.5**	**226.2**	**6,461.8**
Acquisition Cost of Proved Properties	4.2	-	4.2	-	-	-	4.2
Total Exploration & Development Expenditures	**5,969.3**	**270.5**	**6,239.8**	**134.7**	**91.5**	**226.2**	**6,466.0**
Gathering, Processing and Other	604.0	52.1	656.1	0.1	0.2	0.3	656.4
Asset Retirement Costs	51.8	69.8	121.6	6.8	4.8	11.6	133.2
Total Expenditures	**6,625.1**	**392.4**	**7,017.5**	**141.6**	**96.5**	**238.1**	**7,255.6**
Proceeds from Sales in Place	(1,252.0)	(177.9)	(1,429.9)	(3.3)	-	(3.3)	(1,433.2)
Net Expenditures	**$ 5,373.1**	**$ 214.5**	**$ 5,587.6**	**$ 138.3**	**$ 96.5**	**$ 234.8**	**$ 5,822.4**

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
RESERVE REPLACEMENT COSTS ($ / Boe) *							
Total Drilling, Before Revisions	**$ 15.97**	**$ 541.00**	**$ 16.67**	**$ 10.86**	**$ 114.38**	**$ 17.14**	**$ 16.68**
All-in Total, Net of Revisions	**$ 18.00**	**$ (21.81)**	**$ 19.55**	**$ 16.04**	**$ 91.50**	**$ 24.06**	**$ 19.68**
RESERVE REPLACEMENT *							
Drilling Only	**307%**	**4%**	**281%**	**55%**	**114%**	**57%**	**248%**
All-in Total, Net of Revisions & Dispositions	**216%**	**-111%**	**189%**	**37%**	**143%**	**41%**	**167%**

*** *See attached reconciliation schedule for calculation methodology***

EOG RESOURCES, INC.

QUANTITATIVE RECONCILIATION OF TOTAL EXPLORATION AND DEVELOPMENT EXPENDITURES FOR DRILLING ONLY (NON-GAAP) AND TOTAL EXPLORATION AND DEVELOPMENT EXPENDITURES (NON-GAAP) AS USED IN THE CALCULATION OF RESERVE REPLACEMENT COSTS ($ / BOE) TO TOTAL COSTS INCURRED IN EXPLORATION AND DEVELOPMENT ACTIVITIES (GAAP)

(Unaudited; in millions, except ratio information)

The following chart reconciles Total Costs Incurred in Exploration and Development Activities (GAAP) to Total Exploration and Development Expenditures for Drilling Only (Non-GAAP) and Total Exploration and Development Expenditures (Non-GAAP), as used in the calculation of Reserve Replacement Costs per Boe. There are numerous ways that industry participants present Reserve Replacement Costs, including “Drilling Only” and “All-In”, which reflect total exploration and development expenditures divided by total net proved reserve additions from extensions and discoveries only, or from all sources. Combined with Reserve Replacement, these statistics provide management and investors with an indication of the results of the current year capital investment program. Reserve Replacement Cost statistics are widely recognized and reported by industry participants and are used by EOG management and other third parties for comparative purposes within the industry. Please note that the actual cost of adding reserves will vary from the reported statistics due to timing differences in reserve bookings and capital expenditures. Accordingly, some analysts use three or five year averages of reported statistics, while others prefer to estimate future costs. EOG has not included future capital costs to develop proved undeveloped reserves in exploration and development expenditures.

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
Total Costs Incurred in Exploration and Development Activities (GAAP)	$ 6,021.1	$ 340.3	$ 6,361.4	$ 141.5	$ 96.3	$ 237.8	$ 6,599.2
Less: Asset Retirement Costs	(51.8)	(69.8)	(121.6)	(6.8)	(4.8)	(11.6)	(133.2)
Acquisition Cost of Proved Properties	(4.2)	-	(4.2)	-	-	-	(4.2)
Total Exploration & Development Expenditures for Drilling Only (Non-GAAP) (a)	**$ 5,965.1**	**$ 270.5**	**$ 6,235.6**	**$ 134.7**	**$ 91.5**	**$ 226.2**	**$ 6,461.8**
Total Costs Incurred in Exploration and Development Activities (GAAP)	$ 6,021.1	$ 340.3	$ 6,361.4	$ 141.5	$ 96.3	$ 237.8	$ 6,599.2
Less: Asset Retirement Costs	(51.8)	(69.8)	(121.6)	(6.8)	(4.8)	(11.6)	(133.2)
Total Exploration & Development Expenditures (Non-GAAP) (b)	**$ 5,969.3**	**$ 270.5**	**$ 6,239.8**	**$ 134.7**	**$ 91.5**	**$ 226.2**	**$ 6,466.0**
Net Proved Reserve Additions From All Sources - Oil Equivalents (MMBoe)							
Revisions due to price (c)	(11.7)	(3.0)	(14.7)	(1.7)	-	(1.7)	(16.4)
Revisions other than price	(30.8)	(9.9)	(40.7)	(2.3)	0.2	(2.1)	(42.8)
Purchases in place	0.5	-	0.5	-	-	-	0.5
Extensions, discoveries and other additions (d)	373.6	0.5	374.1	12.4	0.8	13.2	387.3
Total Proved Reserve Additions (e)	**331.6**	**(12.4)**	**319.2**	**8.4**	**1.0**	**9.4**	**328.6**
Sales in place	(68.2)	-	(68.2)	-	-	-	(68.2)
Net Proved Reserve Additions From All Sources (f)	**263.4**	**(12.4)**	**251.0**	**8.4**	**1.0**	**9.4**	**260.4**
Production (g)	**121.7**	**11.2**	**132.9**	**22.5**	**0.7**	**23.2**	**156.1**
RESERVE REPLACEMENT COSTS ($ / BOE)							
Total Drilling, Before Revisions (a / d)	**$ 15.97**	**$ 541.00**	**$ 16.67**	**$ 10.86**	**$ 114.38**	**$ 17.14**	**$ 16.68**
All-in Total, Net of Revisions (b / e)	**$ 18.00**	**$ (21.81)**	**$ 19.55**	**$ 16.04**	**$ 91.50**	**$ 24.06**	**$ 19.68**
All-in Total, Excluding Revisions Due to Price (b / (e - c))	**$ 17.39**	**$ (28.78)**	**$ 18.69**	**$ 13.34**	**$ 91.50**	**$ 20.38**	**$ 18.74**
RESERVE REPLACEMENT							
Drilling Only (d / g)	**307%**	**4%**	**281%**	**55%**	**114%**	**57%**	**248%**
All-in Total, Net of Revisions & Dispositions (f / g)	**216%**	**-111%**	**189%**	**37%**	**143%**	**41%**	**167%**
All-in Total, Excluding Revisions Due to Price ((f - c) / g)	**226%**	**-84%**	**200%**	**45%**	**143%**	**48%**	**177%**

EOG RESOURCES, INC.

QUANTITATIVE RECONCILIATION OF NET DEBT (NON-GAAP) AND TOTAL CAPITALIZATION (NON-GAAP) AS USED IN THE CALCULATION OF THE NET DEBT-TO-TOTAL CAPITALIZATION RATIO (NON-GAAP) TO CURRENT AND LONG-TERM DEBT (GAAP) AND TOTAL CAPITALIZATION (GAAP)

(Unaudited; in millions, except ratio data)

The following chart reconciles Current and Long-Term Debt (GAAP) to Net Debt (Non-GAAP) and Total Capitalization (GAAP) to Total Capitalization (Non-GAAP), as used in the Net Debt-to-Total Capitalization ratio calculation. A portion of the cash is associated with international subsidiaries; tax considerations may impact debt paydown. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize Net Debt and Total Capitalization (Non-GAAP) in their Net Debt-to-Total Capitalization ratio calculation. EOG management uses this information for comparative purposes within the industry.

	December 31, 2011
Total Stockholders' Equity - (a)	$ 12,641
Current and Long-Term Debt - (b)	5,009
Less: Cash	(616)
Net Debt (Non-GAAP) - (c)	4,393
Total Capitalization (GAAP) - (a) + (b)	$ 17,650
Total Capitalization (Non-GAAP) - (a) + (c)	$ 17,034
Debt-to-Total Capitalization (GAAP) - (b) / [(a) + (b)]	**28%**
Net Debt-to-Total Capitalization (Non-GAAP) - (c) / [(a) + (c)]	**26%**

EOG RESOURCES, INC.
CRUDE OIL AND NATURAL GAS FINANCIAL
COMMODITY DERIVATIVE CONTRACTS

Presented below is a comprehensive summary of EOG's crude oil and natural gas derivative contracts as of February 16, 2012 with notional volumes expressed in Bbld and MMBtud and prices expressed in $/Bbl and $/MMBtu. EOG accounts for financial commodity derivative contracts using the mark-to-market accounting method.

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	49,000	105.42
July 1, 2012 through August 31, 2012	32,000	104.95
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 15,000 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 15,000 Bbld at an average price of $106.50 per barrel for the period September 1, 2012 through February 28, 2013.

NATURAL GAS DERIVATIVE CONTRACTS

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2012 [2]		
January 1, 2012 through February 29, 2012 (closed)	525,000	$5.44
March 1, 2012 through December 31, 2012	525,000	5.44
2013 [3]		
January 1, 2013 through December 31, 2013	150,000	$4.79
2014 [3]		
January 1, 2014 through December 31, 2014	150,000	$4.79

(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 425,000 MMBtud at an average price of $5.44 per MMBtu for the period from March 1, 2012 through December 31, 2012.

(3) 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.

Definitions

Bbld	Barrels per day.
$/Bbl	Dollars per barrel.
MMBtud	Million British thermal units per day.
$/MMBtu	Dollars per million British thermal units.

EOG RESOURCES, INC.

FIRST QUARTER AND FULL YEAR 2012 FORECAST AND BENCHMARK COMMODITY PRICING

(a) First Quarter and Full Year 2012 Forecast

The forecast items for the first quarter and full year 2012 set forth below for EOG Resources, Inc. (EOG) are based on current available information and expectations as of the date of the accompanying press release. EOG undertakes no obligation, other than as required by applicable law, to update or revise this forecast, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise. This forecast, which should be read in conjunction with the accompanying press release and EOG's related Current Report on Form 8-K filing, replaces and supersedes any previously issued guidance or forecast.

(b) Benchmark Commodity Pricing

EOG bases United States, Canada and Trinidad crude oil and condensate price differentials upon the West Texas Intermediate crude oil price at Cushing, Oklahoma, using the simple average of the NYMEX settlement prices for each trading day within the applicable calendar month.

EOG bases United States and Canada natural gas price differentials upon the natural gas price at Henry Hub, Louisiana, using the simple average of the NYMEX settlement prices for the last three trading days of the applicable month.

	ESTIMATED RANGES (Unaudited)					
	1Q 2012			Full Year 2012		
Daily Production						
Crude Oil and Condensate Volumes (MBbld)						
United States	118.0	-	133.0	130.0	-	147.5
Canada	6.5	-	7.5	5.5	-	7.8
Trinidad	2.0	-	2.8	1.0	-	2.0
Other International	0.0	-	0.0	0.1	-	0.2
Total	126.5	-	143.3	136.6	-	157.5
Natural Gas Liquids Volumes (MBbld)						
United States	46.0	-	53.0	49.2	-	59.2
Canada	0.6	-	1.0	0.6	-	1.0
Total	46.6	-	54.0	49.8	-	60.2
Natural Gas Volumes (MMcfd)						
United States	1,015	-	1,045	995	-	1,035
Canada	90	-	107	82	-	102
Trinidad	315	-	345	335	-	363
Other International	9	-	11	8	-	10
Total	1,429	-	1,508	1,420	-	1,510
Crude Oil Equivalent Volumes (MBoed)						
United States	333.2	-	360.2	345.0	-	379.2
Canada	22.1	-	26.3	19.8	-	25.8
Trinidad	54.5	-	60.3	56.8	-	62.5
Other International	1.4	-	1.8	1.4	-	1.9
Total	411.2	-	448.6	423.0	-	469.4

ESTIMATED RANGES
(Unaudited)

	1Q 2012					Full Year 2012				
Operating Costs										
Unit Costs ($/Boe)										
Lease and Well	$	6.48	-	$	7.08	$	6.48	-	$	7.08
Transportation Costs	$	3.12	-	$	3.48	$	3.24	-	$	3.66
Depreciation, Depletion and Amortization	$	17.22	-	$	18.42	$	17.70	-	$	18.60
Expenses ($MM)										
Exploration, Dry Hole and Impairment	$	101.5	-	$	120.0	$	450.0	-	$	490.0
General and Administrative	$	78.0	-	$	84.0	$	338.0	-	$	358.0
Gathering and Processing	$	19.0	-	$	23.0	$	72.0	-	$	90.0
Capitalized Interest	$	13.0	-	$	17.0	$	60.0	-	$	72.0
Net Interest	$	45.0	-	$	51.0	$	175.0	-	$	195.0
Taxes Other Than Income (% of Revenue)		6.1%	-		6.5%		5.5%	-		6.5%
Income Taxes										
Effective Rate		35%	-		50%		35%	-		45%
Current Taxes ($MM)	$	70	-	$	85	$	290	-	$	310
Capital Expenditures ($MM) - FY 2012 (Excluding Acquisitions)										
Exploration and Development, Excluding Facilities						$	6,200	-	$	6,300
Exploration and Development Facilities						$	630	-	$	675
Gathering, Processing and Other						$	570	-	$	600
Pricing - (Refer to *Benchmark Commodity Pricing* in text)										
Crude Oil and Condensate ($/Bbl)										
Differentials										
United States - below WTI	$	0.50	-	$	3.00	$	0.25	-	$	1.75
Canada - below WTI	$	7.00	-	$	11.00	$	5.00	-	$	8.00
Trinidad - below WTI	$	2.50	-	$	3.50	$	6.00	-	$	7.00
Natural Gas ($/Mcf)										
Differentials										
United States - below NYMEX Henry Hub	$	0.05	-	$	0.20	$	0.05	-	$	0.25
Canada - below NYMEX Henry Hub	$	0.42	-	$	0.63	$	0.45	-	$	0.90
Realizations										
Trinidad	$	2.75	-	$	3.25	$	2.25	-	$	3.00
Other International	$	5.00	-	$	6.00	$	5.00	-	$	5.90

Definitions

$/Bbl	U.S. Dollars per barrel
$/Boe	U.S. Dollars per barrel of oil equivalent
$/Mcf	U.S. Dollars per thousand cubic feet
$MM	U.S. Dollars in millions
MBbld	Thousand barrels per day
MBoed	Thousand barrels of oil equivalent per day
MMcfd	Million cubic feet per day
NYMEX	New York Mercantile Exchange
WTI	West Texas Intermediate