EOG Resources, Inc.

EOG Resources Reports Fourth Quarter and Full Year 2013 Results; Exceeds Crude Oil and Total Company Production Growth Targets; Increases Potential Eagle Ford Reserves by 45 Percent; Raises Common Stock Dividend by 33 Percent

HOUSTON, Feb. 24, 2014 /PRNewswire/ --

- Delivers 40 Percent Year-Over-Year Total Company Crude Oil Growth and 9 Percent Total Company Production Growth
- Reports Strong Year-Over-Year Increases in Adjusted Non-GAAP Net Income Per Share, Adjusted EBITDAX and Discretionary Cash Flow
- Realizes 16 Percent ROE and 12 Percent ROCE
- Increases Eagle Ford Potential Reserves by 45 Percent to 3.2 BnBoe, Net After Royalty
- Achieves 264 Percent Reserve Replacement at Excellent Finding Costs
- Records Successive Stellar Results from the Eagle Ford, Bakken and Leonard Plays
- Raises Common Stock Dividend by 33 Percent – 15th Increase in 15 Years – and Announces Two-For-One Stock Split
- Targets 27 Percent Crude Oil Production and 11.5 Percent Total Company Growth for 2014

EOG Resources, Inc. (NYSE: EOG) (EOG) today reported full year 2013 net income of $2,197 million, or $8.04 per share, as compared to $570 million, or $2.11 per share, for the full year 2012. For the fourth quarter 2013, EOG reported net income of $580 million, or $2.12 per share. This compares to a fourth quarter 2012 net loss of $505 million, or $1.88 per share.

Adjusted non-GAAP net income for the full year 2013 was $2,246 million, or $8.22 per share, and for the full year 2012 was $1,536 million, or $5.67 per share. Adjusted non-GAAP net income for the fourth quarter 2013 was $548 million, or $2.00 per share, and for the fourth quarter 2012 was $437 million, or $1.61 per share.

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 fourth quarter 2013 excluded a previously disclosed non-cash net gain of $40.5 million ($25.6 million after tax, or $0.09 per share) on the mark-to-market of financial commodity contracts and net gains on asset dispositions of $7.2 million, net of tax ($0.03 per share). During the fourth quarter 2013, the net cash inflow related to financial commodity contracts was $1.0 million ($0.7 million after tax, or $0.00 per share). (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income to GAAP net income.)

EOG posted excellent financial metrics for 2013 with increases of 45 percent in adjusted non-GAAP net income per share, 29 percent in discretionary cash flow and 26 percent in adjusted EBITDAX, compared to 2012. Indicative of its high rate-of-return and disciplined crude oil investment programs, EOG also posted 16 percent ROE and 12 percent ROCE last year. (Please refer to the attached tables for the reconciliation of adjusted non-GAAP net income to GAAP net income, non-GAAP discretionary cash flow to net cash provided by operating activities (GAAP), adjusted EBITDAX (non-GAAP) to income before interest expense and income taxes (GAAP) and non-GAAP inputs to GAAP inputs as used in the calculation of ROE and ROCE.)

Operational Highlights

In the fourth quarter 2013, EOG increased its U.S. crude oil and condensate production by 53 percent, while total company crude oil and condensate production rose by 50 percent over the same prior year period. Total company liquids production – crude oil, condensate and natural gas liquids (NGLs) – climbed 41 percent.

For the full year, total company crude oil and condensate production increased 40 percent year-over-year, driven by 42 percent growth in the U.S. Total company liquids production increased 34 percent, while total natural gas production decreased 11 percent. Overall total company production increased 9 percent compared to the prior year.

"2013 was an outstanding year for EOG," said William R. "Bill" Thomas, Chairman and Chief Executive Officer. "Through virtually flawless execution of our operations plan, we generated robust crude oil production growth concurrent with strong ROE and ROCE ratios, while deleveraging the company. Our 2013 financial metrics and year-end balance sheet reflect the value of EOG's high quality crude oil investments."

South Texas Eagle Ford

The single largest source of EOG's extraordinary crude oil production growth in 2013 was its mammoth South Texas Eagle Ford play. EOG increased well productivity and initial production rates by augmenting its technical knowledge of shale resources and the associated completion processes. Based on these significant improvements, EOG increased the net potential recoverable reserve estimate on its crude oil acreage by 45 percent to 3.2 billion barrels of oil equivalent (BnBoe) from 2.2 BnBoe. While continuing to decrease spacing between wells in certain areas, the average net reserves per well increased to 450 thousand barrels of crude oil equivalent (Mboe) from 400 Mboe.

Recent Eagle Ford wells include the Boothe Unit #3H, #4H and #17H in Gonzales County, which began initial production during the fourth quarter at 2,630 to 3,375 barrels of crude oil per day (Bopd) with 365 to 520 barrels per day (Bpd) of NGLs and 2.1 to 3.0 million cubic feet per day (MMcfd) of natural gas. The Rudolph Unit #1H was turned to sales at 4,230 Bopd with 505 Bpd of NGLs and 2.9 MMcfd of natural gas. The Nichols Unit #3H had an initial crude oil production rate of 3,830 Bpd with 390 Bpd of NGLs and 2.3 MMcfd of natural gas. In Karnes County, the Fleetwood Unit #1H and #2H began production at 3,630 and 3,435 Bopd with 345 and 350 Bpd of NGLs, respectively, and 2.0 MMcfd of natural gas each. EOG has 100 percent working interest in these seven wells.

The Wilde Trust Unit #1H, #2H and #3H, completed in the second quarter 2013, had combined cumulative production of over 960,000 barrels of crude oil over a 200-day period. EOG holds a 100 percent working interest in these Gonzales County wells.

Southwest of Gonzales and Karnes counties, the Naylor Jones Unit 42 #1H, #2H and 60 #2H began production at rates ranging from 1,755 to 2,050 Bopd with 195 to 205 Bpd of NGLs and 1.1 to 1.2 MMcfd of natural gas in McMullen County. In La Salle County, the Further Unit #1H and #2H had initial crude oil production rates of 2,605 and 2,550 Bpd with 125 and 155 Bpd of NGLs and 725 and 900 thousand cubic feet per day (Mcfd) of natural gas, respectively. EOG has 100 percent working interest in these five wells.

"To put our Eagle Ford position in simple terms, our current reserve potential is almost four times what we estimated four years ago when EOG discovered the play. With approximately 7,200 total identified individual net well locations, we still have about 6,000 net wells to drill across EOG's 120-mile crude oil window," Thomas said. "Our in-house talent keeps finding ways to improve development of this world-class shale asset where we hold a critical mass of very desirable acreage. This gives EOG a lot of running room to produce better and better results over a long period of time."

North Dakota Bakken

In North Dakota where EOG focused drilling activity on two key areas, the Bakken Core and Antelope Extension, 2013 results surpassed expectations. Ongoing improvements in drilling and completion techniques transformed what was a steady development drilling program into a high rate-of-return crude oil growth play. By confirming downspacing economics in the Bakken Core, EOG ramped up its drilling plan from one to four wells per section, while increasing the average recoverable resource per well.

In the Bakken Core in Mountrail County, the Wayzetta 30-3230H and 31-3230H, in which EOG has 59 percent working interest, began production at 2,510 and 2,540 Bopd, respectively. The Wayzetta 35-1920H, in which EOG has a 60 percent working interest, had an initial production rate of 2,240 Bopd with 1.2 MMcfd of rich natural gas.

In the Antelope Extension, EOG drilled the Hawkeye 2-2501H in McKenzie County. The well, in which EOG has 80 percent working interest, began production with 2,075 Bopd and 3.8 MMcfd of rich natural gas.

Delaware Basin Leonard

EOG's Permian Basin activity also was a solid contributor to its overall 2013 domestic crude oil production growth. Although EOG tested the prospectivity of multiple target zones in its three distinct horizontal resource plays last year, it initially concentrated on the Midland Basin Wolfcamp, followed by the Delaware Basin Leonard and Wolfcamp. Based on compelling well results, EOG shifted activity to the Delaware Basin Leonard during the second half of 2013.

In Lea County, New Mexico, two Leonard wells were drilled and completed in the second half of 2013 and turned to sales early in 2014. The Vaca 24 Fed Com #5H and #6H had initial crude oil production rates of 1,520 and 1,380 Bpd with 265 and 170 Bpd of NGLs and 1.5 and 0.9 MMcfd of natural gas, respectively. EOG has 89 percent working interest in these wells.

Reserves

At December 31, 2013, EOG's total company net proved reserves of 2,119 million barrels of crude oil equivalent (MMBoe) increased 17 percent over year-end 2012. Total company net proved developed reserves increased 19 percent to 1,127 MMBoe. Total U.S. net proved crude oil and condensate reserves increased 31 percent. Total proved liquids reserves increased 25 percent year-over-year, comprising 60 percent of total company proved reserves at December 31, 2013.

In 2013:

- Total reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 264 percent at a total reserve replacement cost of $13.42 per barrel of oil equivalent (Boe), based on exploration and development expenditures of $6,859 million, net of non-cash lease acquisition and asset retirement costs.
- Total liquids reserve replacement from all sources – the ratio of net reserve additions from drilling, acquisitions, total revisions and dispositions to total production – was 346 percent.
- Reserve replacement from drilling – the ratio of extensions, discoveries and other additions to total production – was 212 percent. Crude oil reserve replacement from drilling in the United States was 297 percent.
- In the United States, total reserve replacement from all sources, net of revisions and dispositions, was 307 percent at a reserve replacement cost of $12.57 per Boe based on exploration and development expenditures of $6,290 million, net of non-cash lease acquisition and asset retirement costs.

(Please refer to the attached tables for the calculation of total reserve replacement, total reserve replacement costs, total liquids reserve replacement, reserve replacement from drilling, U.S. total reserve replacement and U.S. reserve replacement costs.)

For the 26th consecutive year, internal reserve estimates were within 5 percent of those prepared by the independent reserve engineering firm of DeGolyer and MacNaughton (D&M). D&M conducted an independent engineering analysis of properties comprising about 82 percent of EOG's 2013 proved reserves on a Boe basis.

Hedging Activity

EOG increased the amount of crude oil hedges in place for 2014 compared to 2013. For February 2014, EOG has crude oil financial price swap contracts in place for 171,000 Bopd at a weighted average price of $96.35 per barrel, excluding unexercised options. For March 2014, EOG has crude oil financial price swap contracts in place for 181,000 Bopd at a weighted average price of $96.55 per barrel, excluding unexercised options. For the period April 1 through May 31, 2014, EOG has crude oil financial price swap contracts in place for 171,000 Bopd at a weighted average price of $96.55 per barrel, excluding unexercised options. For June 2014, EOG has crude oil financial price swap contracts in place for 161,000 Bopd at a weighted average price of $96.33 per barrel, excluding unexercised options. For the period July 1 through December 31, 2014, EOG has crude oil financial price swap contracts in place for 64,000 Bopd at a weighted average price of $95.18 per barrel, excluding unexercised options.

EOG also has hedged natural gas volumes. For the period March 1 through December 31, 2014, EOG has natural gas financial price swap contracts in place for 330,000 million British thermal units per day (MMBtud) at a weighted average price of $4.55 per million British thermal units (MMBtu), excluding unexercised options.

For the period January 1 through December 31, 2015, EOG has natural gas financial price swap contracts in place for 175,000 MMBtud at a weighted average price of $4.51 MMBtu, excluding unexercised options. (For a comprehensive summary of crude oil and natural gas derivative contracts, please refer to the attached tables.)

Capital Structure

During 2013, EOG's cash flows from operating activities exceeded total capital expenditures. Total proceeds from asset sales were $761 million.

At December 31, 2013, EOG's total debt outstanding was $5,913 million for a debt-to-total capitalization ratio of 28 percent. Taking into account cash on the balance sheet of $1.3 billion at year-end, EOG's net debt was $4,595 million for a net debt-to-total capitalization ratio of 23 percent, down from 29 percent at year-end 2012. (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).)

2014 Plans

EOG is targeting 27 percent total company crude oil production growth in 2014, driven by 29 percent growth in the U.S. Although natural gas prices have recently increased due to cold winter weather in North America, EOG's extensive portfolio of crude oil and liquids-rich resources offer far superior returns compared to alternative natural gas drilling investments. EOG does not plan to allocate capital to North American dry natural gas drilling in 2014. As a result, its North American natural gas production is expected to decline 6 percent. Total company production is expected to increase 11.5 percent.

Capital expenditures for 2014 are expected to range from $8.1 to $8.3 billion, including production facilities and midstream expenditures, but excluding acquisitions.

"EOG is directing a larger percentage of its 2014 capital budget to the Eagle Ford and Bakken where we have tremendous drilling opportunity with excellent rates of return," Thomas said. "By increasing activity in these plays, we expect the momentum and operational efficiencies we've created to continue."

With plans to drill approximately 520 net wells across its Eagle Ford acreage during 2014, EOG expects the play's extremely robust production will again lead the company's overall crude oil growth.

EOG is increasing activity in the North Dakota Bakken/Three Forks where it is targeting an 80-net well drilling program, an uptick over 2013. Operations will be primarily in the Core, followed by the Antelope Extension area. Based on successful drilling results from the first and second intervals of the Three Forks formation in the Antelope Extension last year, EOG intends to test additional benches during 2014.

As a result of sound technical progress achieved last year, EOG is shifting its Permian capital expenditure program from the Midland Basin to the higher rate-of-return Delaware Basin in 2014. Concentrating on the Leonard play and, to a lesser extent, the Wolfcamp, the emphasis will be on implementing efficient drilling patterns while continuing to test additional prospective zones.

"2014 should be another great year for EOG. We will stay focused on improving EOG's overall returns as we pursue a wealth of high rate-of-return drilling opportunities across our onshore domestic crude oil plays, and we'll continue to seek exciting new prospects to add to our deep inventory," Thomas said.

Stock Split and Dividend Increase

The board of directors approved a two-for-one stock split in the form of a stock dividend. It will be payable to record holders as of March 17, 2014, and issued March 31, 2014. In addition, the board increased the cash dividend on the common stock by 33 percent. Effective with the dividend payable April 30, 2014 to holders of record as of April 16, 2014, the board declared a post-split quarterly dividend of $0.125 per share on the common stock. The post-split indicated annual rate of $0.50 per share represents the 15th increase in 15 years.

Conference Call February 25, 2014

EOG's fourth quarter and full year 2013 results conference call will be available via live audio webcast at 8 a.m. Central time (9 a.m. Eastern time) on Tuesday, February 25, 2014. To listen, log on to www.eogresources.com. The webcast will be archived on EOG's website through March 10, 2014.

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, statements regarding future commodity prices 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," "should" 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, unknown or currently unforeseen 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 is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and optimize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;
- 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, appropriate gathering, processing, compression, transportation and refining 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, and EOG's ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- 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, facilities, equipment, materials and services;
- the availability and cost of employees and other personnel, facilities, equipment, materials (such as water) 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 (by EOG or third parties) of production, gathering, processing, refining, 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 conditions and developments around the world (such as political instability and armed conflict), 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;
- physical, electronic and cyber security breaches; and
- the other factors described under Item 1A, "Risk Factors", on pages 17 through 26 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2013 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.

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, 2013, 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. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	**2012**	**2013**	**2012**
Net Operating Revenues	$ 3,749.0	$ 3,011.8	$ 14,487.1	$ 11,682.6
Net Income (Loss)	$ 580.2	$ (505.0)	$ 2,197.1	$ 570.3
Net Income (Loss) Per Share				
Basic	$ 2.14	$ (1.88)	$ 8.13	$ 2.13
Diluted	$ 2.12	$ (1.88)	$ 8.04	$ 2.11
Average Number of Common Shares				
Basic	270.9	268.9	270.2	267.6
Diluted	274.0	268.9	273.1	270.8

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	**2012**	**2013**	**2012**
Net Operating Revenues				
Crude Oil and Condensate	$ 2,168,073	$ 1,460,684	$ 8,300,647	$ 5,659,437
Natural Gas Liquids	217,794	208,493	773,970	727,177
Natural Gas	411,425	418,329	1,681,029	1,571,762
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	40,504	66,416	(166,349)	393,744
Gathering, Processing and Marketing	888,680	903,404	3,643,749	3,096,694
Gains (Losses) on Asset Dispositions, Net	11,996	(55,474)	197,565	192,660
Other, Net	10,551	9,959	56,507	41,162
Total	3,749,023	3,011,811	14,487,118	11,682,636
Operating Expenses				
Lease and Well	288,921	234,349	1,105,978	1,000,052
Transportation Costs	224,506	169,789	853,044	601,431
Gathering and Processing Costs	26,349	25,542	107,871	97,945
Exploration Costs	30,378	48,660	161,346	185,569
Dry Hole Costs	15,395	1,965	74,655	14,970
Impairments	109,509	1,020,496	286,941	1,270,735
Marketing Costs	901,940	880,451	3,648,840	3,035,494
Depreciation, Depletion and Amortization	915,257	786,344	3,600,976	3,169,703
General and Administrative	91,066	86,679	348,312	331,545
Taxes Other Than Income	165,378	135,597	623,944	495,395
Total	2,768,699	3,389,872	10,811,907	10,202,839
Operating Income (Loss)	980,324	(378,061)	3,675,211	1,479,797
Other Income (Expense), Net	(8,732)	(8,407)	(2,865)	14,495
Income (Loss) Before Interest Expense and Income Taxes	971,592	(386,468)	3,672,346	1,494,292
Interest Expense, Net	52,510	59,354	235,460	213,552

Income (Loss) Before Income Taxes	919,082	(445,822)	3,436,886	1,280,740
Income Tax Provision	338,888	59,177	1,239,777	710,461
Net Income (Loss)	$ 580,194	$ (504,999)	$ 2,197,109	$ 570,279
Dividends Declared per Common Share	$ 0.1875	$ 0.17	$ 0.75	$ 0.68

EOG RESOURCES, INC.
OPERATING HIGHLIGHTS
(Unaudited)

	Three Months Ended December 31,		**Twelve Months Ended December 31,**	
	2013	**2012**	**2013**	**2012**
Wellhead Volumes and Prices				
Crude Oil and Condensate Volumes (MBbld) (A)				
United States	235.4	154.1	212.1	149.3
Canada	7.7	7.5	7.0	7.0
Trinidad	1.1	1.0	1.2	1.5
Other International (B)	0.1	0.1	0.1	0.1
Total	244.3	162.7	220.4	157.9
Average Crude Oil and Condensate Prices ($/Bbl) (C)				
United States	$ 97.23	$ 98.72	$ 103.81	$ 98.38
Canada	78.02	85.59	87.05	86.08
Trinidad	84.91	83.93	90.30	92.26
Other International (B)	89.97	87.34	89.11	89.57
Composite	96.57	98.02	103.20	97.77
Natural Gas Liquids Volumes (MBbld) (A)				
United States	66.6	57.0	64.3	55.1
Canada	0.8	0.8	0.9	0.8
Total	67.4	57.8	65.2	55.9
Average Natural Gas Liquids Prices ($/Bbl) (C)				
United States	$ 35.01	$ 35.36	$ 32.46	$ 35.41
Canada	45.17	42.50	39.45	44.13
Composite	35.13	35.45	32.55	35.54
Natural Gas Volumes (MMcfd) (A)				
United States	873	981	908	1,034
Canada	69	84	76	95
Trinidad	372	335	355	378
Other International (B)	7	8	8	9
Total	1,321	1,408	1,347	1,516
Average Natural Gas Prices ($/Mcf) (C)				
United States	$ 3.28	$ 2.93	$ 3.32	$ 2.51
Canada	3.34	2.98	3.08	2.49
Trinidad	3.60	4.12	3.68	3.72
Other International (B)	6.01	5.75	6.45	5.71
Composite	3.39	3.23	3.42	2.83
Crude Oil Equivalent Volumes (MBoed) (D)				
United States	447.6	374.6	427.9	376.6
Canada	19.9	22.3	20.5	23.6
Trinidad	63.0	56.8	60.4	64.5
Other International (B)	1.3	1.4	1.3	1.7
Total	531.8	455.1	510.1	466.4
Total MMBoe (D)	48.9	41.9	186.2	170.7

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

(B) Other International includes EOG's United Kingdom, China and Argentina 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, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,318,209	$ 876,435
Accounts Receivable, Net	1,658,853	1,656,618
Inventories	563,268	683,187
Assets from Price Risk Management Activities	8,260	166,135
Income Taxes Receivable	4,797	29,163
Deferred Income Taxes	244,606	-
Other	274,022	178,346
Total	4,072,015	3,589,884
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	42,821,803	38,126,298
Other Property, Plant and Equipment	2,967,085	2,740,619
Total Property, Plant and Equipment	45,788,888	40,866,917
Less: Accumulated Depreciation, Depletion and Amortization	(19,640,052)	(17,529,236)
Total Property, Plant and Equipment, Net	26,148,836	23,337,681
Other Assets	353,387	409,013
Total Assets	$ 30,574,238	$ 27,336,578
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 2,254,418	$ 2,078,948
Accrued Taxes Payable	159,365	162,083
Dividends Payable	50,795	45,802
Liabilities from Price Risk Management Activities	127,542	7,617
Deferred Income Taxes	-	22,838
Current Portion of Long-Term Debt	6,579	406,579
Other	263,017	200,191
Total	2,861,716	2,924,058
Long-Term Debt	5,906,642	5,905,602
Other Liabilities	865,067	894,758
Deferred Income Taxes	5,522,354	4,327,396
Commitments and Contingencies		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 273,189,220 Shares and 271,958,495 Shares Issued at December 31, 2013 and 2012, respectively	202,732	202,720
Additional Paid in Capital	2,646,879	2,500,340
Accumulated Other Comprehensive Income	415,834	439,895
Retained Earnings	12,168,277	10,175,631
Common Stock Held in Treasury, 103,415 Shares and 326,264 Shares at December 31, 2013 and 2012, respectively	(15,263)	(33,822)
Total Stockholders' Equity	15,418,459	13,284,764
Total Liabilities and Stockholders' Equity	$ 30,574,238	$ 27,336,578

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

	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012
Cash Flows from Operating Activities		

Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 2,197,109	$ 570,279
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	3,600,976	3,169,703
Impairments	286,941	1,270,735
Stock-Based Compensation Expenses	134,055	127,778
Deferred Income Taxes	874,765	292,938
Gains on Asset Dispositions, Net	(197,565)	(192,660)
Other, Net	11,072	672
Dry Hole Costs	74,655	14,970
Mark-to-Market Commodity Derivative Contracts		
Total (Gains) Losses	166,349	(393,744)
Net Cash Received from Settlements of Commodity Derivative Contracts	116,361	711,479
Excess Tax Benefits from Stock-Based Compensation	(55,831)	(67,035)
Other, Net	18,205	14,411
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(23,613)	(178,683)
Inventories	53,402	(156,762)
Accounts Payable	178,701	(17,150)
Accrued Taxes Payable	75,142	78,094
Other Assets	(109,567)	(118,520)
Other Liabilities	(20,382)	36,114
Changes in Components of Working Capital Associated with Investing and Financing Activities	(51,361)	74,158
Net Cash Provided by Operating Activities	7,329,414	5,236,777
Investing Cash Flows		
Additions to Oil and Gas Properties	(6,697,091)	(6,735,316)
Additions to Other Property, Plant and Equipment	(363,536)	(619,800)
Proceeds from Sales of Assets	760,557	1,309,776
Changes in Restricted Cash	(65,814)	-
Changes in Components of Working Capital Associated with Investing Activities	51,106	(73,923)
Net Cash Used in Investing Activities	(6,314,778)	(6,119,263)
Financing Cash Flows		
Long-Term Debt Repayments	(400,000)	-
Long-Term Debt Borrowings	-	1,234,138
Dividends Paid	(199,178)	(181,080)
Excess Tax Benefits from Stock-Based Compensation	55,831	67,035
Treasury Stock Purchased	(63,784)	(58,592)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	38,730	82,887
Debt Issuance Costs	-	(1,578)
Repayment of Capital Lease Obligation	(5,780)	(2,824)
Other, Net	255	(235)
Net Cash (Used in) Provided by Financing Activities	(573,926)	1,139,751
Effect of Exchange Rate Changes on Cash	1,064	3,444
Increase in Cash and Cash Equivalents	441,774	260,709
Cash and Cash Equivalents at Beginning of Period	876,435	615,726
Cash and Cash Equivalents at End of Period	$ 1,318,209	$ 876,435

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

The following chart adjusts the three-month and twelve-month periods ended December 31, 2013 and 2012 reported Net Income (Loss) (GAAP) to reflect actual net cash received from settlements of commodity derivative contracts by eliminating the unrealized mark-to-market (gains) losses from these transactions, to eliminate the net (gains) losses on asset dispositions in North America and to add back impairment charges related to certain of EOG's non-core North American assets in 2013 and 2012. 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,	
	2013	**2012**	**2013**	**2012**
Reported Net Income (Loss) (GAAP)	$ 580,194	$ (504,999)	$ 2,197,109	$ 570,279

Mark-to-Market (MTM) Commodity Derivative Contracts Impact				
Total (Gains) Losses	(40,504)	(66,416)	166,349	(393,744)
Net Cash Received from Settlements of Commodity Derivative Contracts	1,038	155,533	116,361	711,479
Subtotal	(39,466)	89,117	282,710	317,735
After-Tax MTM Impact	(24,901)	57,058	181,372	203,430
Less: Net (Gains) Losses on Asset Dispositions, Net of Tax	(7,232)	35,599	(136,848)	(126,053)
Add: Impairments of Certain North American Assets, Net of Tax	-	849,371	4,425	887,946
Adjusted Net Income (Non-GAAP)	$ 548,061	$ 437,029	$ 2,246,058	$ 1,535,602
Net Income (Loss) Per Share (GAAP)				
Basic	$ 2.14	$ (1.88)	$ 8.13	$ 2.13
Diluted	$ 2.12	$ (1.88)	$ 8.04	$ 2.11
Adjusted Net Income Per Share (Non-GAAP)				
Basic	$ 2.02	$ 1.62	$ 8.31	$ 5.74
Diluted	$ 2.00	$ 1.61	$ 8.22 **(a)**	$ 5.67 **(b)**
Percentage Increase - [(a) - (b)] / (b)			**45%**	
Average Number of Common Shares (GAAP)				
Basic	270,929	268,941	270,170	267,577
Diluted	273,983	268,941	273,114	270,762
Average Number of Shares (Non-GAAP)				
Basic	270,929	268,941	270,170	267,577
Diluted	273,983	271,921	273,114	270,762

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, 2013 and 2012 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), Excess Tax Benefits from Stock-Based Compensation, 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,	
	2013	**2012**	**2013**	**2012**
Net Cash Provided by Operating Activities (GAAP)	$ 2,001,230	$ 1,227,187	$ 7,329,414	$ 5,236,777
Adjustments:				
Exploration Costs (excluding Stock-Based Compensation Expenses)	24,201	42,619	134,531	159,182
Excess Tax Benefits from Stock-Based Compensation	5,601	17,609	55,831	67,035
Changes in Components of Working Capital and Other Assets and Liabilities				
Accounts Receivable	(190,133)	66,509	23,613	178,683
Inventories	7,745	1,996	(53,402)	156,762
Accounts Payable	(33,502)	100,832	(178,701)	17,150
Accrued Taxes Payable	(1,945)	(35,303)	(75,142)	(78,094)
Other Assets	30,768	(1,565)	109,567	118,520
Other Liabilities	31,271	3,757	20,382	(36,114)
Changes in Components of Working				

Capital Associated with Investing and Financing Activities	(21,584)	13,550	51,361		(74,158)	
Discretionary Cash Flow (Non-GAAP)	$ 1,853,652	$ 1,437,191	$ 7,417,454	**(a)**	$ 5,745,743	**(b)**
Percentage Increase - [(a) - (b)] / (b)			**29%**			

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF ADJUSTED EARNINGS BEFORE INTEREST EXPENSE, INCOME TAXES, DEPRECIATION, DEPLETION AND AMORTIZATION, EXPLORATION COSTS, DRY HOLE COSTS, IMPAIRMENTS AND ADDITIONAL ITEMS (ADJUSTED EBITDAX) (NON-GAAP) TO INCOME (LOSS) BEFORE INTEREST EXPENSE AND INCOME TAXES (GAAP)
(Unaudited; in thousands)

The following chart adjusts the three-month and twelve-month periods ended December 31, 2013 and 2012 reported Income (Loss) 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 further adjusts such amount to reflect actual net cash received from settlements of commodity derivative contracts by eliminating the unrealized mark-to-market (MTM) (gains) losses from these transactions and to eliminate the net (gains) losses on asset dispositions in North America in 2013 and 2012. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported Income (Loss) Before Interest Expense and Income Taxes (GAAP) to add back Depreciation, Depletion and Amortization, Exploration Costs, Dry Hole Costs and Impairments and further adjust such amount 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,**			
	2013	**2012**	**2013**		**2012**	
Income (Loss) Before Interest Expense and Income Taxes (GAAP)	$ 971,592	$ (386,468)	$ 3,672,346		$ 1,494,292	
Adjustments:						
Depreciation, Depletion and Amortization	915,257	786,344	3,600,976		3,169,703	
Exploration Costs	30,378	48,660	161,346		185,569	
Dry Hole Costs	15,395	1,965	74,655		14,970	
Impairments	109,509	1,020,496	286,941		1,270,735	
EBITDAX (Non-GAAP)	2,042,131	1,470,997	7,796,264		6,135,269	
Total (Gains) Losses on MTM Commodity Derivative Contracts	(40,504)	(66,416)	166,349		(393,744)	
Net Cash Received from Settlements of Commodity Derivative Contracts	1,038	155,533	116,361		711,479	
Net (Gains) Losses on Asset Dispositions	(11,996)	55,474	(197,565)		(192,660)	
Adjusted EBITDAX (Non-GAAP)	$ 1,990,669	$ 1,615,588	$ 7,881,409	**(a)**	$ 6,260,344	**(b)**
Percentage Increase - [(a) - (b)] / (b)			**26%**			

EOG RESOURCES, INC.
QUANTITATIVE RECONCILIATION OF AFTER-TAX INTEREST EXPENSE (NON-GAAP), ADJUSTED NET INCOME (NON-GAAP), NET DEBT (NON-GAAP) AND TOTAL CAPITALIZATION (NON-GAAP) AS USED IN THE CALCULATIONS OF RETURN ON CAPITAL EMPLOYED (NON-GAAP) AND RETURN ON EQUITY (NON-GAAP) TO INTEREST EXPENSE (GAAP), NET INCOME (GAAP), CURRENT AND LONG-TERM DEBT (GAAP) AND TOTAL CAPITALIZATION (GAAP), RESPECTIVELY
(Unaudited; in millions, except ratio data)

The following chart reconciles Interest Expense (GAAP), Net Income (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Interest Expense (Non-GAAP), Adjusted Net Income (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP), respectively, as used in the Return on Capital Employed (ROCE) and Return on Equity (ROE) calculations. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize After-Tax Interest Expense, Adjusted Net Income, Net Debt and Total Capitalization (Non-GAAP) in their ROCE and ROE calculations. EOG management uses this information for comparative purposes within the industry.

Return on Capital Employed (ROCE)		**2013**		**2012**
Interest Expense	$	235		
Tax Benefit Imputed (based on 35%)		(82)		
After-Tax Interest Expense (Non-GAAP) - (a)	$	153		
Net Income - (b)	$	2,197		
Add: After-Tax Mark-to-Market Commodity Derivative Contracts Impact		182		
Add: Impairments of Certain North American Assets, Net of Tax		4		
Less: Net Gains on Asset Dispositions, Net of Tax		(137)		
Adjusted Net Income (Non-GAAP) - (c)	$	2,246		
Total Stockholders' Equity - (d)	$	15,418	$	13,285
Average Total Stockholders' Equity* - (h)	$	14,352		
Current and Long-Term Debt - (e)	$	5,913	$	6,312
Less: Cash		(1,318)		(876)
Net Debt (Non-GAAP) - (f)	$	4,595	$	5,436
Total Capitalization (GAAP) - (d) + (e)	$	21,331	$	19,597
Total Capitalization (Non-GAAP) - (d) + (f)	$	20,013	$	18,721
Average Total Capitalization (Non-GAAP)* - (g)	$	19,367		
ROCE (Non-GAAP) - [(a) + (b)] / (g)		**12.1%**		
ROCE (Non-GAAP) - [(a) + (c)] / (g)		**12.4%**		
Return on Equity (ROE)				
ROE (Non-GAAP) - (b) / (h)		**15.3%**		
ROE (Non-GAAP) - (c) / (h)		**15.6%**		

*Average for the current and immediately preceding year

EOG RESOURCES, INC.

CRUDE OIL AND NATURAL GAS FINANCIAL COMMODITY DERIVATIVE CONTRACTS

EOG has entered into additional crude oil and natural gas derivative contracts since filing its Current Report on Form 8-K dated January 7, 2014. Presented below is a comprehensive summary of EOG's crude oil and natural gas derivative contracts at February 24, 2014, 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)
2014 (1)		
January 2014 (closed)	156,000	$ 96.30
February 2014	171,000	96.35
March 2014	181,000	96.55
April 1, 2014 through May 31, 2014	171,000	96.55
June 2014	161,000	96.33
July 1, 2014 through December 31, 2014	64,000	95.18

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional three-month, six-month and nine-month periods. Options covering a notional volume of 10,000 Bbld are exercisable on or about March 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of $96.60 per barrel for each month during the period April 1, 2014 through December 31, 2014. Options covering a notional volume of 10,000 Bbld are exercisable on or about May 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of $100.00 per barrel for

each month during the period June 1, 2014 through August 31, 2014. Options covering a notional volume of 118,000 Bbld are exercisable on or about June 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 118,000 Bbld at an average price of $96.64 per barrel for each month during the period July 1, 2014 through December 31, 2014. Options covering a notional volume of 69,000 Bbld are exercisable on or about December 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 69,000 Bbld at an average price of $95.20 per barrel for each month during the period January 1, 2015 through June 30, 2015.

NATURAL GAS DERIVATIVE CONTRACTS

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2014 (2)		
January 2014 (closed)	230,000	$ 4.51
February 2014 (closed)	710,000	4.57
March 1, 2014 through December 31, 2014	330,000	4.55
2015 (3)		
January 1, 2015 through December 31, 2015	175,000	$ 4.51

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. All 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 480,000 MMBtud at an average price of $4.63 per MMBtu for each month during the period March 1, 2014 through December 31, 2014.

(3) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. All 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 175,000 MMBtud at an average price of $4.51 per MMBtu for each month during the period January 1, 2015 through December 31, 2015.

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

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.

	At December 31, 2013	At December 31, 2012
Total Stockholders' Equity - (a)	$ 15,418	$ 13,285
Current and Long-Term Debt - (b)	5,913	6,312
Less: Cash	(1,318)	(876)
Net Debt (Non-GAAP) - (c)	4,595	5,436
Total Capitalization (GAAP) - (a) + (b)	$ 21,331	$ 19,597
Total Capitalization (Non-GAAP) - (a) + (c)	$ 20,013	$ 18,721
Debt-to-Total Capitalization (GAAP) - (b) / [(a) + (b)]	28%	32%
Net Debt-to-Total Capitalization (Non-GAAP) - (c) / [(a) + (c)]	23%	29%

EOG RESOURCES, INC.
RESERVES SUPPLEMENTAL DATA
(Unaudited)

2013 NET PROVED RESERVES RECONCILIATION SUMMARY

	United States	Canada	North America	Trinidad	Other Int'l	Total Int'l	Total
CRUDE OIL & CONDENSATE (MMBbls)							
Beginning Reserves	671.0	17.9	688.9	3.0	8.9	11.9	700.8
Revisions	57.6	(5.9)	51.7	(1.0)	(0.1)	(1.1)	50.6
Purchases in place	1.1	-	1.1	-	-	-	1.1
Extensions, discoveries and other additions	230.0	0.7	230.7	-	0.1	0.1	230.8
Sales in place	(2.3)	-	(2.3)	-	-	-	(2.3)
Production	(77.4)	(2.6)	(80.0)	(0.4)	(0.1)	(0.5)	(80.5)
Ending Reserves	**880.0**	**10.1**	**890.1**	**1.6**	**8.8**	**10.4**	**900.5**
NATURAL GAS LIQUIDS (MMBbls)							
Beginning Reserves	318.4	1.6	320.0	-	-	-	320.0
Revisions	12.2	(0.1)	12.1	-	-	-	12.1
Purchases in place	1.2	-	1.2	-	-	-	1.2
Extensions, discoveries and other additions	69.2	-	69.2	-	-	-	69.2
Sales in place	(1.5)	-	(1.5)	-	-	-	(1.5)
Production	(23.5)	(0.3)	(23.8)	-	-	-	(23.8)
Ending Reserves	**376.0**	**1.2**	**377.2**	-	-	-	**377.2**
NATURAL GAS (Bcf)							
Beginning Reserves	4,036.0	98.3	4,134.3	588.2	17.0	605.2	4,739.5
Revisions	264.0	31.4	295.4	(17.4)	(0.7)	(18.1)	277.3
Purchases in place	5.7	-	5.7	-	-	-	5.7
Extensions, discoveries and other additions	504.7	0.1	504.8	79.5	9.8	89.3	594.1
Sales in place	(69.4)	-	(69.4)	-	-	-	(69.4)
Production	(342.3)	(27.7)	(370.0)	(129.6)	(2.8)	(132.4)	(502.4)
Ending Reserves	**4,398.7**	**102.1**	**4,500.8**	**520.7**	**23.3**	**544.0**	**5,044.8**
OIL EQUIVALENTS (MMBoe)							
Beginning Reserves	1,662.1	35.8	1,697.9	101.1	11.7	112.8	1,810.7
Revisions	113.9	(0.7)	113.2	(3.9)	(0.3)	(4.2)	109.0
Purchases in place	3.2	-	3.2	-	-	-	3.2
Extensions, discoveries and other additions	383.4	0.7	384.1	13.2	1.7	14.9	399.0
Sales in place	(15.4)	-	(15.4)	-	-	-	(15.4)
Production	(158.0)	(7.5)	(165.5)	(22.0)	(0.5)	(22.5)	(188.0)
Ending Reserves	**1,989.2**	**28.3**	**2,017.5**	**88.4**	**12.6**	**101.0**	**2,118.5**

Net Proved Developed

Reserves (MMBoe)							
At December 31, 2012	**840.6**	**24.3**	**864.9**	**81.8**	**3.1**	**84.9**	**949.8**
At December 31, 2013	**1,015.4**	**24.8**	**1,040.2**	**83.9**	**3.4**	**87.3**	**1,127.5**

2013 EXPLORATION AND DEVELOPMENT EXPENDITURES ($ Millions)

	United States	**Canada**	**North America**	**Trinidad**	**Other Int'l**	**Total Int'l**	**Total**
Acquisition Cost of Unproved Properties	$ 411.6	$ 2.5	$ 414.1	$ -	$ -	$ -	$ 414.1
Exploration Costs	273.8	19.7	293.5	16.1	67.6	83.7	377.2
Development Costs	5,488.9	136.5	5,625.4	123.7	202.9	326.6	5,952.0
Total Drilling	**6,174.3**	**158.7**	**6,333.0**	**139.8**	**270.5**	**410.3**	**6,743.3**
Acquisition Cost of Proved Properties	120.2	-	120.2	-	-	-	120.2
Total Exploration & Development Expenditures	**6,294.5**	**158.7**	**6,453.2**	**139.8**	**270.5**	**410.3**	**6,863.5**
Gathering, Processing and Other	360.0	2.8	362.8	-	0.8	0.8	363.6
Asset Retirement Costs	84.3	13.0	97.3	0.5	36.6	37.1	134.4
Total Expenditures	**6,738.8**	**174.5**	**6,913.3**	**140.3**	**307.9**	**448.2**	**7,361.5**
Proceeds from Sales of Assets	(362.3)	(397.8)	(760.1)	-	-	-	(760.1)
Net Expenditures	**$ 6,376.5**	**$ (223.3)**	**$ 6,153.2**	**$ 140.3**	**$ 307.9**	**$ 448.2**	**$ 6,601.4**
RESERVE REPLACEMENT COSTS ($ / Boe) *							
Total Drilling, Before Revisions	**$ 16.09**	**$ 226.71**	**$ 16.47**	**$ 10.59**	**$ 159.12**	**$ 27.54**	**$ 16.89**
All-in Total, Net of Revisions	**$ 12.57**	**NA**	**$ 12.88**	**$ 15.03**	**$ 193.21**	**$ 38.35**	**$ 13.42**
All-in Total, Excluding Revisions Due to Price	**$ 14.12**	**NA**	**$ 14.66**	**$ 15.03**	**$ 193.21**	**$ 38.35**	**$ 15.23**
RESERVE REPLACEMENT *							
Drilling Only	**243%**	**9%**	**232%**	**60%**	**340%**	**66%**	**212%**
All-in Total, Net of Revisions & Dispositions	**307%**	**0%**	**293%**	**42%**	**280%**	**48%**	**264%**
All-in Total, Excluding Revisions Due to Price	**272%**	**-75%**	**256%**	**42%**	**280%**	**48%**	**231%**
All-in Total, Liquids	**364%**	**-183%**	**349%**	**-250%**	**0%**	**-200%**	**346%**

***   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)	$ 6,378.8	$ 171.7	$ 6,550.5	$ 140.3	$ 307.1	$ 447.4	$ 6,997.9
Less: Asset Retirement Costs	(84.3)	(13.0)	(97.3)	(0.5)	(36.6)	(37.1)	(134.4)
Non-Cash Acquisition Costs of Unproved Properties	(5.0)	-	(5.0)	-	-	-	(5.0)
Acquisition Cost of Proved Properties	(120.2)	-	(120.2)	-	-	-	(120.2)
Total Exploration & Development Expenditures for Drilling Only (Non-GAAP) (a)	**$ 6,169.3**	**$ 158.7**	**$ 6,328.0**	**$ 139.8**	**$ 270.5**	**$ 410.3**	**$ 6,738.3**
Total Costs Incurred in Exploration and Development Activities (GAAP)	$ 6,378.8	$ 171.7	$ 6,550.5	$ 140.3	$ 307.1	$ 447.4	$ 6,997.9
Less: Asset Retirement Costs	(84.3)	(13.0)	(97.3)	(0.5)	(36.6)	(37.1)	(134.4)
Non-Cash Acquisition Costs of Unproved Properties	(5.0)	-	(5.0)	-	-	-	(5.0)
Total Exploration & Development Expenditures (Non-GAAP) (b)	**$ 6,289.5**	**$ 158.7**	**$ 6,448.2**	**$ 139.8**	**$ 270.5**	**$ 410.3**	**$ 6,858.5**

Total Expenditures (GAAP)	$ 6,738.8	$ 174.5	$ 6,913.3	$ 140.3	$ 307.9	$ 448.2	$ 7,361.5
Less: Asset Retirement Costs	(84.3)	(13.0)	(97.3)	(0.5)	(36.6)	(37.1)	(134.4)
Non-Cash Acquisition Costs of Unproved Properties	(5.0)	-	(5.0)	-	-	-	(5.0)
Total Cash Expenditures (Non-GAAP)	**$ 6,649.5**	**$ 161.5**	**$ 6,811.0**	**$ 139.8**	**$ 271.3**	**$ 411.1**	**$ 7,222.1**
Net Proved Reserve Additions From All Sources - Oil Equivalents (MMBoe)							
Revisions due to price (c)	55.2	5.6	60.8	-	-	-	60.8
Revisions other than price	58.7	(6.3)	52.4	(3.9)	(0.3)	(4.2)	48.2
Purchases in place	3.2	-	3.2	-	-	-	3.2
Extensions, discoveries and other additions (d)	383.4	0.7	384.1	13.2	1.7	14.9	399.0
Total Proved Reserve Additions (e)	**500.5**	-	**500.5**	**9.3**	**1.4**	**10.7**	**511.2**
Sales in place	(15.4)	-	(15.4)	-	-	-	(15.4)
Net Proved Reserve Additions From All Sources (f)	**485.1**	-	**485.1**	**9.3**	**1.4**	**10.7**	**495.8**
Production (g)	**158.0**	**7.5**	**165.5**	**22.0**	**0.5**	**22.5**	**188.0**
RESERVE REPLACEMENT COSTS ($ / BOE)							
Total Drilling, Before Revisions (a / d)	**$ 16.09**	**$ 226.71**	**$ 16.47**	**$ 10.59**	**$ 159.12**	**$ 27.54**	**$ 16.89**
All-in Total, Net of Revisions (b / e)	**$ 12.57**	**NA**	**$ 12.88**	**$ 15.03**	**$ 193.21**	**$ 38.35**	**$ 13.42**
All-in Total, Excluding Revisions Due to Price (b / (e - c))	**$ 14.12**	**NA**	**$ 14.66**	**$ 15.03**	**$ 193.21**	**$ 38.35**	**$ 15.23**
RESERVE REPLACEMENT							
Drilling Only (d / g)	**243%**	**9%**	**232%**	**60%**	**340%**	**66%**	**212%**
All-in Total, Net of Revisions & Dispositions (f / g)	**307%**	**0%**	**293%**	**42%**	**280%**	**48%**	**264%**
All-in Total,							

Excluding Revisions Due to Price ((f - c) / g)	**272%**	**-75%**	**256%**	**42%**	**280%**	**48%**	**231%**
Net Proved Reserve Additions From All Sources - Liquids (MMBbls)							
Revisions	69.8	(6.0)	63.8	(1.0)	(0.1)	(1.1)	62.7
Purchases in place	2.3	-	2.3	-	-	-	2.3
Extensions, discoveries and other additions (h)	299.2	0.7	299.9	-	0.1	0.1	300.0
Total Proved Reserve Additions	**371.3**	**(5.3)**	**366.0**	**(1.0)**	-	**(1.0)**	**365.0**
Sales in place	(3.8)	-	(3.8)	-	-	-	(3.8)
Net Proved Reserve Additions From All Sources (i)	**367.5**	**(5.3)**	**362.2**	**(1.0)**	-	**(1.0)**	**361.2**
Production (j)	**100.9**	**2.9**	**103.8**	**0.4**	**0.1**	**0.5**	**104.3**
RESERVE REPLACEMENT - LIQUIDS							
Drilling Only (h / j)	**297%**	**24%**	**289%**	**0%**	**100%**	**20%**	**288%**
All-in Total, Net of Revisions & Dispositions (i / j)	**364%**	**-183%**	**349%**	**-250%**	**0%**	**-200%**	**346%**

EOG RESOURCES, INC.
FIRST QUARTER AND FULL YEAR 2014 FORECAST AND BENCHMARK COMMODITY PRICING

(a) First Quarter and Full Year 2014 Forecast

The forecast items for the first quarter and full year 2014 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 2014			Full Year 2014		
Daily Production						
Crude Oil and Condensate Volumes (MBbld)						
United States	246.0	-	256.0	263.0	-	283.0
Canada	5.5	-	6.5	4.5	-	6.5
Trinidad	0.7	-	1.1	0.6	-	1.0

Other International	0.0	-	0.0	0.0	-	1.2
Total	252.2	-	263.6	268.1	-	291.7
Natural Gas Liquids Volumes (MBbld)						
United States	63.5	-	67.5	68.0	-	77.0
Canada	0.5	-	0.7	0.6	-	0.8
Total	64.0	-	68.2	68.6	-	77.8
Natural Gas Volumes (MMcfd)						
United States	845	-	875	850	-	880
Canada	56	-	68	55	-	69
Trinidad	365	-	385	350	-	370
Other International	6	-	8	8	-	12
Total	1,272	-	1,336	1,263	-	1,331
Crude Oil Equivalent Volumes (MBoed)						
United States	450.4	-	469.4	472.7	-	506.6
Canada	15.3	-	18.5	14.3	-	18.8
Trinidad	61.5	-	65.3	58.9	-	62.7
Other International	1.0	-	1.3	1.3	-	3.2
Total	528.2	-	554.5	547.2	-	591.3
Operating Costs						
Unit Costs ($/Boe)						
Lease and Well	$ 6.35	-	$ 6.65	$ 6.25	-	$ 6.75
Transportation Costs	$ 4.90	-	$ 5.10	$ 4.80	-	$ 5.20
Depreciation, Depletion and Amortization	$ 18.65	-	$ 19.35	$ 18.40	-	$ 19.20
Expenses ($MM)						
Exploration, Dry Hole and Impairment	$ 140.0	-	$ 160.0	$ 525.0	-	$ 575.0
General and Administrative	$ 95.0	-	$ 105.0	$ 390.0	-	$ 410.0
Gathering and Processing	$ 30.0	-	$ 36.0	$ 120.0	-	$ 140.0
Capitalized Interest	$ 14.0	-	$ 16.0	$ 55.0	-	$ 65.0
Net Interest	$ 48.0	-	$ 52.0	$ 190.0	-	$ 210.0
Taxes Other Than Income (% of Wellhead Revenue)	6.0%	-	6.4%	6.0%	-	6.4%
Income Taxes						
Effective Rate	35%	-	40%	35%	-	40%
Current Taxes ($MM)	$ 105	-	$ 120	$ 425	-	$ 445
Capital Expenditures ($MM) - FY 2014 (Excluding Acquisitions)						
Exploration and Development, Excluding Facilities				$ 6,450		$ 6,550
Exploration and Development Facilities				$ 880		$ 920
Gathering, Processing and Other				$ 770		$ 810
Pricing - (Refer to Benchmark Commodity Pricing in text)						
Crude Oil and Condensate ($/Bbl)						
Differentials						
United States - (above) below WTI	$ (1.50)	-	$ 0.00	$ (0.80)	-	$ 0.20
Canada - (above) below WTI	$ 11.25	-	$ 14.00	$ 10.00	-	$ 14.00
Trinidad - (above) below WTI	$ 8.00	-	$ 12.00	$ 8.00	-	$ 12.00
Natural Gas Liquids						
Realizations as % of WTI						
United States	35%	-	43%	31%	-	37%
Canada	37%	-	42%	30%	-	40%
Natural Gas ($/Mcf)						
Differentials						
United States - (above) below NYMEX Henry Hub	$ (0.25)	-	$ 0.25	$ 0.25	-	$ 0.70
Canada - (above) below NYMEX Henry Hub	$ 0.50	-	$ 0.80	$ 0.40	-	$ 0.80
Realizations						
Trinidad	$ 2.75	-	$ 3.25	$ 2.75	-	$ 3.25
Other International	$ 5.00	-	$ 7.00	$ 4.00	-	$ 6.00

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

SOURCE EOG Resources, Inc.

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https://investors.eogresources.com/2014-02-24-EOG-Resources-Reports-Fourth-Quarter-and-Full-Year-2013-Results-Exceeds-Crude-Oil-and-Total-Company-Production-Growth-Targets-Increases-Potential-Eagle-Ford-Reserves-by-45-Percent-Raises-Common-Stock-Dividend-by-33-Percent