EOG Resources, Inc.

EOG Resources Reports Fourth Quarter and Full Year 2014 Results and Announces Return-Driven Capital Program for 2015

HOUSTON, Feb. 18, 2015 /PRNewswire/ --

- Realizes 16 Percent ROE and 14 Percent ROCE for 2014
- Delivers 31 Percent Year-Over-Year Total Company Crude Oil Production Growth and 17 Percent Total Company Production Growth
- Reports Robust Year-Over-Year Increases in Adjusted Non-GAAP Net Income Per Share and Discretionary Cash Flow
- Increases Reserves 18 Percent and Replaces 273 Percent of its Production at Low Finding Costs
- Continues to Achieve Outstanding Performance from the Eagle Ford, Bakken and Delaware Basin
- Announces Disciplined 2015 Capital Program, Plans to Delay Well Completions and Targets Flat Year-Over-Year Crude Oil Production

EOG Resources, Inc. (NYSE: EOG) (EOG) today reported fourth quarter 2014 net income of $445 million, or $0.81 per share. This compares to fourth quarter 2013 net income of $580 million, or $1.06 per share. For the full year, EOG reported net income of $2,915 million, or $5.32 per share, compared to $2,197 million, or $4.02 per share, for the full year 2013.

Adjusted non-GAAP net income for the fourth quarter 2014 was $432 million, or $0.79 per share, and for the fourth quarter 2013 was $548 million, or $1.00 per share. Adjusted non-GAAP net income for the full year 2014 was $2,716 million, or $4.95 per share, and for the full year 2013 was $2,246 million, or $4.11 per share. Adjusted non-GAAP net income is calculated by matching realizations to settlement months and making certain other adjustments in order to exclude one-time items. (Please refer to the attached tables for the reconciliation of non-GAAP measures to GAAP.)

EOG achieved strong financial metrics for 2014. Adjusted non-GAAP net income per share increased 20 percent and discretionary cash flow increased 14 percent, compared to 2013. For the year, EOG posted ROE of 16 percent and ROCE of 14 percent. (Please refer to the attached tables for the reconciliation of non-GAAP measures to GAAP and for return calculations.)

In the fourth quarter 2014, EOG increased its U.S. crude oil and condensate production by 28 percent, while total company crude oil and condensate production rose by 26 percent, compared to the same prior year period.

For the full year, crude oil and condensate production increased 31 percent year over year, driven by 33 percent growth in the United States. Natural gas liquids (NGLs) production increased 23 percent, while natural gas production was flat. Overall total company production increased 17 percent.

"EOG delivered both high returns and strong growth in 2014, a unique accomplishment in the energy sector," said William R. "Bill" Thomas, Chairman and Chief Executive Officer. "Our returns-focused capital discipline has been at the core of EOG's culture since the very beginning. We are confident we will continue to earn healthy returns on our capital program during this commodity down cycle and, more importantly, emerge stronger and poised for significant long-term growth."

2015 Capital Plan

EOG's primary goal for 2015 is to position the company to resume long-term growth once crude oil prices recover. The company is not interested in accelerating crude oil production in a low-price environment.

Capital expenditures for 2015 are expected to range from $4.9 to $5.1 billion, including production facilities and midstream expenditures, and excluding acquisitions. This 40 percent reduction compared to 2014 reflects EOG's commitment to capital discipline in a low crude oil price environment.

Capital will be allocated primarily to EOG's highest rate-of-return oil assets, the Eagle Ford, Delaware Basin and Bakken plays. To further enhance capital efficiency, EOG plans to utilize rigs under existing commitments and delay a significant number of completions. Delaying completions increases returns, adds substantial net present value and prepares the company to resume strong oil growth when commodity prices recover.

Due to reduced capital spending and delayed completions, EOG expects to complete approximately 45 percent fewer wells in 2015 versus 2014. Therefore, the midpoint for 2015 total company crude oil production guidance is essentially flat year over year. Once again, EOG plans to minimize investment in domestic dry natural gas drilling. As a result, its U.S. natural gas production and total company production are expected to decline modestly.

Year after year, EOG has relentlessly focused on advancing its industry-leading completion technology and driving down unit costs through efficiency gains. That will not change in 2015.

Finally, the company expects to use its strong balance sheet to capitalize on unique opportunities created by this low-price environment to add high-quality acreage.

"The downturn in oil prices will drive significant reductions in global supply and the market will rebalance," Thomas said. "Our goal at EOG is to exit this downturn in better shape than we entered it.

"The current environment brings more opportunities to lower our finding costs, improve our returns and add high-quality drilling inventory. As prices recover, EOG will be poised to resume strong U.S. oil growth," Thomas added.

South Texas Eagle Ford

The Eagle Ford continues to drive EOG's long-term crude oil growth. Each year since its operations began five years ago, EOG has improved per-well productivity and successfully downspaced wells through advancements in completion technology. Estimated potential net reserves have grown 250 percent from 900 million barrels of oil equivalent (MMBoe) in 2009 to 3.2 billion barrels of oil equivalent today. EOG has over 5,500 remaining net well locations in the Eagle Ford – over a decade of drilling. This world-class play will continue to be EOG's primary source of returns and growth for years to come.

During the fourth quarter of 2014, the Eagle Ford continued to deliver impressive well results across EOG's acreage. The Korth Unit 6H through 9H had initial production rates ranging from 3,955 to 5,480 barrels of oil per day (Bopd), 355 to 535 barrels per day (Bpd) of NGLs and 2.1 to 3.1 million cubic feet per day (MMcfd) of natural gas. This four-well pattern drilled in Karnes County initially produced over 19,000 Bopd, 1,700 Bpd of NGLs and 10 MMcfd of natural gas, collectively.

On the western side of EOG's Eagle Ford acreage in La Salle County, the Naylor Jones Unit 14-1H and 15-1H had initial production rates of 2,460 and 2,850 Bopd, plus 165 and 190 Bpd of NGLs and 975 thousand cubic feet per day (Mcfd) and 1.1 MMcfd of natural gas, respectively. In McMullen County, the Los Compadres Unit 1H was brought online at an initial production rate of 2,535 Bopd, with 180 Bpd of NGLs and 1.1 MMcfd of natural gas.

In 2015, EOG will execute a balanced drilling program across the length of its Eagle Ford acreage. Due to advancements achieved in the western acreage during the last two years, returns are competitive with the east and a balanced drilling program will maximize operational efficiencies. EOG plans to complete about 345 net wells in the Eagle Ford compared to 534 in 2014.

Delaware Basin

In 2014, EOG expanded activity in the Delaware Basin resulting in the identification of considerable new potential across three separate targets. EOG's technical understanding of the basin advanced, confirmed by a series of impressive well results in the second half of the year. With lower costs and improved well productivity, EOG's drilling program across the Delaware Basin is now consistently generating rates-of-return which are on par with the Eagle Ford and Bakken plays.

In the Second Bone Spring Sand, EOG applied advanced completion techniques and determined that at least 90,000 net acres of its leasehold are prospective in the oil window. In the Leonard, the company continued to make technical progress. EOG piloted multiple downspacing tests which could eventually increase the size of its crude oil drilling inventory in the Leonard play.

In the Delaware Basin Wolfcamp, EOG made significant advancements in well productivity, breaking its own record initial production rates with each successive well. Most recently, EOG completed three wells in Reeves County. The State Harrison Ranch 57 #1501H and #2101H and the State Apache 57 #202H had initial production rates ranging from 1,500 to over 2,000 Bopd, with 550 to 700 Bpd of NGLs and 4.0 to 4.5 MMcfd of natural gas.

Also in 2014, EOG confirmed that 90,000 net acres of its total 140,000 net-acre Wolfcamp position are in the oil window.

In 2015, capital expenditures will increase in the Permian Basin as EOG expects to complete about 95 net wells, a 53 percent increase compared to 2014. Capital will be directed to development drilling in the northern Delaware Basin targeting EOG's three highest-return plays – the Leonard, the Second Bone Spring Sand and the Wolfcamp. Ongoing technical work will determine the most efficient approach to develop these three plays and enable EOG to test additional prospective zones.

North Dakota Bakken

In 2014, EOG's drilling activity in North Dakota was directed to two key areas, the Bakken Core and the Antelope Extension. The focus this past year has been to drive down drilling costs and further advance completions to improve well performance and allow for additional downspacing. In the fourth quarter, EOG completed a six-well pattern in the Bakken Core area spaced at 700 feet between wells which delivered a combined initial production rate of 9,450 Bopd and 5 MMcfd of rich natural gas. Initial results from these completion and downspacing pilots are very encouraging, and additional pilots and testing in 2015 are designed to uncover the best long-term development plan for this crude oil growth play.

Also in 2014, EOG stepped out from the Bakken to test the Three Forks formation, particularly in the Antelope Extension, with some notable well results. Due to the low-price crude oil environment, additional development of this high-potential target will be put on hold.

Capital allocated to the Bakken will decrease significantly in 2015. EOG expects to complete about 25 net wells compared to 59 in 2014.

Wyoming Rockies

2014 was a big year for exploration in Wyoming as EOG announced four Rockies plays, the Codell and Niobrara in the DJ Basin, and the Parkman and Turner in the Powder River Basin. All four plays generated strong rates of return and consistent well results in 2014.

EOG completed several excellent wells in the fourth quarter in these emerging plays. In the DJ Basin Codell, the Windy 515-1819H and Windy 509-1806H had initial production rates of 1,490 and 1,355 Bopd, with 145 and 110 Bpd of NGLs, and 515 and 375 Mcfd of natural gas, respectively.

In the Powder River Basin, three recently completed Parkman wells, the Mary's Draw 4-0310H, 26-0310H and 209-0310H, had initial production rates of 1,160, 1,425 and 1,205 Bopd, with 460, 525, 1,015 Mcfd of rich natural gas, respectively. Two Turner completions are the Mary's Draw 7-24H and 8-24RH with initial production rates of 915 Bopd and 1.9 MMcfd of rich natural gas, and 925 Bopd and 1.9 MMcfd of rich natural gas, respectively.

EOG does not plan significant development of its DJ Basin or Powder River Basin assets until crude oil prices improve.

"EOG continues to demonstrate its leadership in growing high-return drilling inventory organically," Thomas said. "Last year at this time, we announced an increase to the reserves and drilling inventory in the Eagle Ford. A quarter later, we announced four plays in the Rockies. By the third quarter, we had delineated the Second Bone Spring Sand and identified the Wolfcamp oil window in the Delaware Basin. As in years past, we added more high-return inventory than we drilled during the year."

Reserves

Driven almost entirely by strong liquids reserves growth in the United States, EOG increased total company net proved reserves 18 percent in 2014. At year-end, total company net proved reserves were 2,497 MMBoe, comprised of 46 percent crude oil and condensate, 19 percent NGLs and 35 percent natural gas.

Net proved reserve additions replaced 273 percent of EOG's 2014 production at a finding and development cost of $12.16 per barrel of oil equivalent (Boe). Excluding reserve revisions due to commodity price changes, the replacement ratio was 249 percent at a cost of $13.25 per Boe. (For more reserves detail, including calculation of reserve replacement ratios and reserve replacement costs, please refer to the attached tables.)

For the 27th consecutive year, internal reserve estimates were within 5 percent of estimates independently prepared by DeGolyer and MacNaughton.

Hedging Activity

For February 1 through June 30, 2015, EOG has crude oil financial price swap contracts in place for 47,000 Bopd at a weighted average price of $91.22 per barrel. For July 1 through December 31, 2015, EOG has crude oil financial price swap contracts in place for 10,000 Bopd at a weighted average price of $89.98 per barrel, excluding unexercised options.

For March 1 through December 31, 2015, EOG has natural gas financial price swap contracts in place for approximately 182,000 million British thermal units per day at a weighted average price of $4.51 per million British thermal units, excluding unexercised options. (For a comprehensive summary of crude oil and natural gas derivative contracts, please refer to the attached tables.)

Capital Structure

During 2014, EOG's cash flows from operating activities exceeded total capital expenditures. Total proceeds from asset sales were $569 million.

At December 31, 2014, EOG's total debt outstanding was $5,910 million for a debt-to-total capitalization ratio of 25 percent. Taking into account cash on the balance sheet of $2,087 million at year-end, EOG's net debt was $3,823 million for a net debt-to-total capitalization ratio of 18 percent, down from 23 percent at year-end 2013. (Please refer to the attached tables for the reconciliation of non-GAAP debt measures to GAAP.)

Dividend

The board of directors declared a dividend of $0.1675 per share on EOG's Common Stock, payable April 30, 2015, to stockholders of record as of April 16, 2015. The indicated annual rate is $0.67 per share.

Conference Call February 19, 2015

EOG's fourth quarter and full year 2014 results conference call will be available via live audio webcast at 8 a.m. Central time (9 a.m. Eastern time) on Thursday, February 19, 2015. To listen, log on to www.eogresources.com. The webcast will be archived on EOG's website through March 5, 2015.

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, extent and duration 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 13 through 20 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2014 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). 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, 2014, 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,	
	2014	2013	2014	2013
Net Operating Revenues	$ 4,645.5	$ 3,749.0	$ 18,035.3	$ 14,487.1
Net Income	$ 444.6	$ 580.2	$ 2,915.5	$ 2,197.1
Net Income Per Share				
Basic	$ 0.82	$ 1.07	$ 5.36	$ 4.07
Diluted	$ 0.81	$ 1.06	$ 5.32	$ 4.02
Average Number of Common Shares				
Basic	544.6	541.9	543.4	540.3
Diluted	549.2	548.0	548.5	546.2

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	2014	2013
Net Operating Revenues				
Crude Oil and Condensate	$ 2,054,901	$ 2,168,073	$ 9,742,480	$ 8,300,647
Natural Gas Liquids	180,916	217,794	934,051	773,970
Natural Gas	407,494	411,425	1,916,386	1,681,029
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	750,154	40,504	834,273	(166,349)
Gathering, Processing and Marketing	806,177	888,680	4,046,316	3,643,749
Gains on Asset Dispositions, Net	431,890	11,996	507,590	197,565
Other, Net	13,965	10,551	54,244	56,507
Total	4,645,497	3,749,023	18,035,340	14,487,118
Operating Expenses				
Lease and Well	380,781	288,921	1,416,413	1,105,978
Transportation Costs	242,293	224,506	972,176	853,044
Gathering and Processing Costs	37,785	26,349	145,800	107,871
Exploration Costs	45,167	30,378	184,388	161,346
Dry Hole Costs	18,225	15,395	48,490	74,655
Impairments	535,637	109,509	743,575	286,941
Marketing Costs	862,589	901,940	4,126,060	3,648,840
Depreciation, Depletion and Amortization	1,013,930	915,257	3,997,041	3,600,976
General and Administrative	131,285	91,066	402,010	348,312
Taxes Other Than Income	151,153	165,378	757,564	623,944
Total	3,418,845	2,768,699	12,793,517	10,811,907
Operating Income	1,226,652	980,324	5,241,823	3,675,211
Other Expense, Net	(28,324)	(8,732)	(45,050)	(2,865)
Income Before Interest Expense and Income Taxes	1,198,328	971,592	5,196,773	3,672,346
Interest Expense, Net	49,735	52,510	201,458	235,460
Income Before Income Taxes	1,148,593	919,082	4,995,315	3,436,886
Income Tax Provision	704,005	338,888	2,079,828	1,239,777
Net Income	$ 444,588	$ 580,194	$ 2,915,487	$ 2,197,109
Dividends Declared per Common Share	$ 0.1675	$ 0.0938	$ 0.5850	$ 0.3750

Note: All share and per-share amounts shown have been restated to reflect the 2-for-1 stock split effective March 31, 2014.

EOG RESOURCES, INC.
OPERATING HIGHLIGHTS
(Unaudited)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	2014	2013
Wellhead Volumes and Prices				
Crude Oil and Condensate Volumes (MBbld) [(A)]				
United States	301.5	235.4	282.0	212.1

Canada	5.2	7.7	5.8	7.0
Trinidad	0.9	1.1	1.0	1.2
Other International [B]	0.1	0.1	0.1	0.1
Total	307.7	244.3	288.9	220.4
Average Crude Oil and Condensate Prices ($/Bbl) [C]				
United States	$ 72.76	$ 97.23	$ 92.73	$ 103.81
Canada	72.72	78.02	86.71	87.05
Trinidad	63.65	84.91	84.63	90.30
Other International [B]	87.90	89.97	90.03	89.11
Composite	72.74	96.57	92.58	103.20
Natural Gas Liquids Volumes (MBbld) [A]				
United States	83.1	66.6	79.7	64.3
Canada	0.5	0.8	0.6	0.9
Total	83.6	67.4	80.3	65.2
Average Natural Gas Liquids Prices ($/Bbl) [C]				
United States	$ 23.48	$ 35.01	$ 31.84	$ 32.46
Canada	31.42	45.17	40.73	39.45
Composite	23.53	35.13	31.91	32.55
Natural Gas Volumes (MMcfd) [A]				
United States	921	873	920	908
Canada	51	69	61	76
Trinidad	329	372	363	355
Other International [B]	9	7	9	8
Total	1,310	1,321	1,353	1,347
Average Natural Gas Prices ($/Mcf) [C]				
United States	$ 3.21	$ 3.28	$ 3.93	$ 3.32
Canada	3.64	3.34	4.32	3.08
Trinidad	3.77	3.60	3.65	3.68
Other International [B]	5.04	6.01	5.03	6.45
Composite	3.38	3.39	3.88	3.42
Crude Oil Equivalent Volumes (MBoed) [D]				
United States	538.3	447.6	515.0	427.9
Canada	14.1	19.9	16.7	20.5
Trinidad	55.7	63.0	61.5	60.4
Other International [B]	1.5	1.3	1.5	1.3
Total	609.6	531.8	594.7	510.1
Total MMBoe [D]	56.1	48.9	217.1	186.2

(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 (NGL) and natural gas. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or NGL 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, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 2,087,213	$ 1,318,209
Accounts Receivable, Net	1,779,311	1,658,853
Inventories	706,597	563,268
Assets from Price Risk Management Activities	465,128	8,260
Income Taxes Receivable	71,621	4,797

Deferred Income Taxes	19,618	244,606
Other	286,533	274,022
Total	5,416,021	4,072,015
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	46,503,532	42,821,803
Other Property, Plant and Equipment	3,750,958	2,967,085
Total Property, Plant and Equipment	50,254,490	45,788,888
Less: Accumulated Depreciation, Depletion and Amortization	(21,081,846)	(19,640,052)
Total Property, Plant and Equipment, Net	29,172,644	26,148,836
Other Assets	174,022	353,387
Total Assets	$ 34,762,687	$ 30,574,238

LIABILITIES AND STOCKHOLDERS' EQUITY

Current Liabilities		
Accounts Payable	$ 2,860,548	$ 2,254,418
Accrued Taxes Payable	140,098	159,365
Dividends Payable	91,594	50,795
Liabilities from Price Risk Management Activities	-	127,542
Deferred Income Taxes	110,743	-
Current Portion of Long-Term Debt	6,579	6,579
Other	174,746	263,017
Total	3,384,308	2,861,716
Long-Term Debt	5,903,354	5,906,642
Other Liabilities	939,497	865,067
Deferred Income Taxes	6,822,946	5,522,354
Commitments and Contingencies		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 549,028,374 Shares and 546,378,440 Shares Issued at December 31, 2014 and 2013, respectively	205,492	202,732
Additional Paid in Capital	2,837,150	2,646,879
Accumulated Other Comprehensive Income (Loss)	(23,056)	415,834
Retained Earnings	14,763,098	12,168,277
Common Stock Held in Treasury, 733,517 Shares and 206,830 Shares at December 31, 2014 and 2013, respectively	(70,102)	(15,263)
Total Stockholders' Equity	17,712,582	15,418,459
Total Liabilities and Stockholders' Equity	$ 34,762,687	$ 30,574,238

Note: All share amounts shown have been restated to reflect the 2-for-1 stock split effective March 31, 2014.

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

	Twelve Months Ended December 31,	
	2014	**2013**
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 2,915,487	$ 2,197,109
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	3,997,041	3,600,976
Impairments	743,575	286,941
Stock-Based Compensation Expenses	145,086	134,055
Deferred Income Taxes	1,704,946	874,765
Gains on Asset Dispositions, Net	(507,590)	(197,565)
Other, Net	48,138	11,072
Dry Hole Costs	48,490	74,655
Mark-to-Market Commodity Derivative Contracts		
Total (Gains) Losses	(834,273)	166,349
Net Cash Received from Settlements of Commodity Derivative Contracts	34,007	116,361
Excess Tax Benefits from Stock-Based Compensation	(99,459)	(55,831)
Other, Net	13,009	18,205
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	84,982	(23,613)
Inventories	(161,958)	53,402
Accounts Payable	543,630	178,701
Accrued Taxes Payable	16,486	75,142
Other Assets	(14,448)	(109,567)
Other Liabilities	75,420	(20,382)
Changes in Components of Working Capital Associated with Investing and Financing Activities	(103,414)	(51,361)

Net Cash Provided by Operating Activities	8,649,155	7,329,414
Investing Cash Flows		
Additions to Oil and Gas Properties	(7,519,667)	(6,697,091)
Additions to Other Property, Plant and Equipment	(727,138)	(363,536)
Proceeds from Sales of Assets	569,332	760,557
Changes in Restricted Cash	60,385	(65,814)
Changes in Components of Working Capital Associated with Investing Activities	103,523	51,106
Net Cash Used in Investing Activities	(7,513,565)	(6,314,778)
Financing Cash Flows		
Long-Term Debt Borrowings	496,220	-
Long-Term Debt Repayments	(500,000)	(400,000)
Settlement of Foreign Currency Swap	(31,573)	-
Dividends Paid	(279,695)	(199,178)
Excess Tax Benefits from Stock-Based Compensation	99,459	55,831
Treasury Stock Purchased	(127,424)	(63,784)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	22,249	38,730
Debt Issuance Costs	(895)	-
Repayment of Capital Lease Obligation	(5,966)	(5,780)
Other, Net	(109)	255
Net Cash Used in Financing Activities	(327,734)	(573,926)
Effect of Exchange Rate Changes on Cash	(38,852)	1,064
Increase in Cash and Cash Equivalents	769,004	441,774
Cash and Cash Equivalents at Beginning of Period	1,318,209	876,435
Cash and Cash Equivalents at End of Period	$ 2,087,213	$ 1,318,209

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, 2014 and 2013 reported Net Income (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 on asset dispositions in North America in 2014 and 2013, to add back impairment charges related to certain of EOG's assets in 2014 and 2013 and the tax expense related to the anticipated repatriation of accumulated foreign earnings in future years. 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,	
	2014	**2013**	**2014**	**2013**
Reported Net Income (GAAP)	$ 444,588	$ 580,194	$ 2,915,487	$ 2,197,109
Commodity Derivative Contracts Impact				
(Gains) Losses on Mark-to-Market Commodity Derivative Contracts	(750,154)	(40,504)	(834,273)	166,349
Net Cash Received from Settlements of Commodity Derivative Contracts	222,944	1,038	34,007	116,361
Subtotal	(527,210)	(39,466)	(800,266)	282,710
After-Tax Impact	(339,792)	(24,901)	(514,971)	181,372
Less: Net Gains on Asset Dispositions, Net of Tax	(439,834)	(7,232)	(487,260)	(136,848)
Add: Impairments of Certain Assets, Net of Tax	517,041	-	553,099	4,425
Add: Tax Expense Related to the Repatriation of Accumulated Foreign Earnings in Future Years	249,861	-	249,861	-
Adjusted Net Income (Non-GAAP)	$ 431,864	$ 548,061	$ 2,716,216	$ 2,246,058
Net Income Per Share (GAAP)				
Basic	$ 0.82	$ 1.07	$ 5.36	$ 4.07
Diluted	$ 0.81	$ 1.06	$ 5.32	$ 4.02

Adjusted Net Income Per Share (Non-GAAP)				
Basic	$ 0.79	$ 1.01	$ 5.00	$ 4.16
Diluted	$ 0.79	$ 1.00	$ 4.95	$ 4.11
Adjusted Net Income Per Diluted Share (Non-GAAP) - Percentage Increase	**-21 %**		**20 %**	
Average Number of Common Shares (GAAP)				
Basic	544,579	541,857	543,443	540,341
Diluted	549,153	547,966	548,539	546,227

Reconciliation of Net Gains on Asset Dispositions and Impairments of Certain Assets

	Three Months Ended December 31, 2014
Net Gains on Asset Dispositions	$ 431,890
Less: Exit Costs in General and Administrative Expense	(21,465)
Less: Income Tax Benefit (Expense)	29,409
After-Tax Impact	$ 439,834
Impairments of Certain Assets	$ 444,867
Less: Income Tax (Benefit) Expense	(251,068)
Add: Deferred Tax Valuation Allowance	323,242
After-Tax Impact	$ 517,041

Note: All share and per-share amounts shown have been restated to reflect the 2-for-1 stock split effective March 31, 2014.

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, 2014 and 2013 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,**	
	2014	**2013**	**2014**	**2013**
Net Cash Provided by Operating Activities (GAAP)	$ 2,110,438	$ 2,001,230	$ 8,649,155	$ 7,329,414
Adjustments:				
Exploration Costs (excluding Stock-Based Compensation Expenses)	38,450	24,201	157,453	134,531
Excess Tax Benefits from Stock-Based Compensation	11,632	5,601	99,459	55,831
Changes in Components of Working Capital and Other Assets and Liabilities				
Accounts Receivable	(426,025)	(190,133)	(84,982)	23,613
Inventories	42,792	7,745	161,958	(53,402)
Accounts Payable	23,123	(33,502)	(543,630)	(178,701)
Accrued Taxes Payable	159,926	(1,945)	(16,486)	(75,142)
Other Assets	(47,518)	30,768	14,448	109,567
Other Liabilities	(8,802)	31,271	(75,420)	20,382
Changes in Components of Working Capital Associated with Investing and Financing Activities	(5,154)	(21,584)	103,414	51,361

	Three Months Ended 2014	Three Months Ended 2013	Twelve Months Ended 2014	Twelve Months Ended 2013
Discretionary Cash Flow (Non-GAAP)	$ 1,898,862	$ 1,853,652	$ 8,465,369	$ 7,417,454
Discretionary Cash Flow (Non-GAAP) - Percentage Increase	**2 %**		**14 %**	

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 BEFORE INTEREST EXPENSE AND INCOME TAXES (GAAP)
(Unaudited; in thousands)

The following chart adjusts the three-month and twelve-month periods ended December 31, 2014 and 2013 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 further adjusts such amount to reflect actual net cash received from (payments for) settlements of commodity derivative contracts by eliminating the unrealized mark-to-market (MTM) (gains) losses from these transactions and to eliminate the net gains on asset dispositions in North America in 2014 and 2013. 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 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,	
	2014	**2013**	**2014**	**2013**
Income Before Interest Expense and Income Taxes (GAAP)	$ 1,198,328	$ 971,592	$ 5,196,773	$ 3,672,346
Adjustments:				
Depreciation, Depletion and Amortization	1,013,930	915,257	3,997,041	3,600,976
Exploration Costs	45,167	30,378	184,388	161,346
Dry Hole Costs	18,225	15,395	48,490	74,655
Impairments	535,637	109,509	743,575	286,941
EBITDAX (Non-GAAP)	2,811,287	2,042,131	10,170,267	7,796,264
Total (Gains) Losses on MTM Commodity Derivative Contracts	(750,154)	(40,504)	(834,273)	166,349
Net Cash Received from Settlements of Commodity Derivative Contracts	222,944	1,038	34,007	116,361
Gains on Asset Dispositions, Net	(431,890)	(11,996)	(507,590)	(197,565)
Adjusted EBITDAX (Non-GAAP)	$ 1,852,187	$ 1,990,669	$ 8,862,411	$ 7,881,409
Adjusted EBITDAX (Non-GAAP) - Percentage Increase	**-7 %**		**12 %**	

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, 2014	At December 31, 2013
Total Stockholders' Equity - (a)	$ 17,713	$ 15,418

Current and Long-Term Debt (GAAP) - (b)	5,910	5,913
Less: Cash	(2,087)	(1,318)
Net Debt (Non-GAAP) - (c)	3,823	4,595
Total Capitalization (GAAP) - (a) + (b)	$ 23,623	$ 21,331
Total Capitalization (Non-GAAP) - (a) + (c)	$ 21,536	$ 20,013
Debt-to-Total Capitalization (GAAP) - (b) / [(a) + (b)]	25 %	28 %
Net Debt-to-Total Capitalization (Non-GAAP) - (c) / [(a) + (c)]	18 %	23 %

EOG RESOURCES, INC.
RESERVES SUPPLEMENTAL DATA
(Unaudited)

2014 NET PROVED RESERVES RECONCILIATION SUMMARY

	United States	**Canada**	**North America**	**Trinidad**	**Other Int'l**	**Total Int'l**	**Total**
CRUDE OIL & CONDENSATE (MMBbls)							
Beginning Reserves	880.0	10.1	890.1	1.6	8.8	10.4	900.5
Revisions	28.3	(0.3)	28.0	0.1	(0.1)	-	28.0
Purchases in place	9.7	-	9.7	-	-	-	9.7
Extensions, discoveries and other additions	319.6	-	319.6	-	-	-	319.6
Sales in place	(4.9)	(7.7)	(12.6)	-	-	-	(12.6)
Production	(102.9)	(2.1)	(105.0)	(0.4)	-	(0.4)	(105.4)
Ending Reserves	**1,129.8**	-	**1,129.8**	**1.3**	**8.7**	**10.0**	**1,139.8**
NATURAL GAS LIQUIDS (MMBbls)							
Beginning Reserves	376.0	1.2	377.2	-	-	-	377.2
Revisions	27.5	-	27.5	-	-	-	27.5
Purchases in place	1.8	-	1.8	-	-	-	1.8
Extensions, discoveries and other additions	91.7	-	91.7	-	-	-	91.7
Sales in place	(1.0)	(0.8)	(1.8)	-	-	-	(1.8)
Production	(29.0)	(0.3)	(29.3)	-	-	-	(29.3)
Ending Reserves	**467.0**	**0.1**	**467.1**	**-**	**-**	**-**	**467.1**
NATURAL GAS (Bcf)							
Beginning Reserves	4,398.7	102.1	4,500.8	520.7	23.3	544.0	5,044.8
Revisions	252.2	9.8	262.0	12.9	(4.3)	8.6	270.6
Purchases in place	17.1	-	17.1	-	-	-	17.1
Extensions, discoveries and other additions	638.3	-	638.3	4.5	4.7	9.2	647.5
Sales in place	(52.4)	(78.7)	(131.1)	-	-	-	(131.1)
Production	(348.4)	(22.3)	(370.7)	(132.5)	(3.1)	(135.6)	(506.3)
Ending Reserves	**4,905.5**	**10.9**	**4,916.4**	**405.6**	**20.6**	**426.2**	**5,342.6**
OIL EQUIVALENTS (MMBoe)							
Beginning Reserves	1,989.2	28.3	2,017.5	88.4	12.6	101.0	2,118.5
Revisions	97.8	1.3	99.1	2.2	(0.7)	1.5	100.6

Purchases in place	14.4	-	14.4	-	-	-	14.4
Extensions, discoveries and other additions	517.6	-	517.6	0.8	0.8	1.6	519.2
Sales in place	(14.7)	(21.6)	(36.3)	-	-	-	(36.3)
Production	(190.1)	(6.0)	(196.1)	(22.4)	(0.6)	(23.0)	(219.1)
Ending Reserves	**2,414.2**	**2.0**	**2,416.2**	**69.0**	**12.1**	**81.1**	**2,497.3**
Net Proved Developed Reserves (MMBoe)							
At December 31, 2013	**1,015.4**	**24.8**	**1,040.2**	**83.9**	**3.4**	**87.3**	**1,127.5**
At December 31, 2014	**1,275.4**	**2.0**	**1,277.4**	**67.5**	**3.0**	**70.5**	**1,347.9**

2014 EXPLORATION AND DEVELOPMENT EXPENDITURES ($ Millions)

	United States	**Canada**	**North America**	**Trinidad**	**Other Int'l**	**Total Int'l**	**Total**
Acquisition Cost of Unproved Properties	$ 365.9	$ 4.5	$ 370.4	$ -	$ -	$ -	$ 370.4
Exploration Costs	332.7	13.0	345.7	2.8	47.5	50.3	396.0
Development Costs	6,489.3	70.7	6,560.0	75.5	168.2	243.7	6,803.7
Total Drilling	**7,187.9**	**88.2**	**7,276.1**	**78.3**	**215.7**	**294.0**	**7,570.1**
Acquisition Cost of Proved Properties	138.8	0.3	139.1	-	-	-	139.1
Total Exploration & Development Expenditures	**7,326.7**	**88.5**	**7,415.2**	**78.3**	**215.7**	**294.0**	**7,709.2**
Gathering, Processing and Other	725.0	1.4	726.4	0.2	0.5	0.7	727.1
Asset Retirement Costs	148.9	31.0	179.9	14.0	1.7	15.7	195.6
Total Expenditures	**8,200.6**	**120.9**	**8,321.5**	**92.5**	**217.9**	**310.4**	**8,631.9**
Proceeds from Sales in Place	(175.5)	(393.8)	(569.3)	-	-	-	(569.3)
Net Expenditures	**$8,025.1**	**$ (272.9)**	**$ 7,752.2**	**$ 92.5**	**$ 217.9**	**$ 310.4**	**$8,062.6**
RESERVE REPLACEMENT COSTS ($ / Boe) *							
Total Drilling, Before Revisions	**$ 13.89**	**NA**	**$ 14.06**	**$ 97.88**	**$269.63**	**$183.75**	**$ 14.58**
All-in Total, Net of Revisions	**$ 11.63**	**$ 68.08**	**$ 11.75**	**$ 26.10**	**NA**	**$ 94.84**	**$ 12.16**
All-in Total, Excluding Revisions Due to Price	**$ 12.68**	**$ 88.50**	**$ 12.81**	**$ 26.10**	**NA**	**$ 94.84**	**$ 13.25**
RESERVE REPLACEMENT *							
Drilling Only	**272** %	**0** %	**264** %	**4** %	**133** %	**7** %	**237** %
All-in Total, Net of Revisions & Dispositions	**324** %	**-338** %	**303** %	**13** %	**17** %	**13** %	**273** %
All-in Total, Excluding Revisions Due to Price	**296** %	**-343** %	**277** %	**13** %	**17** %	**13** %	**249** %
All-in Total,							

Liquids	**358** %	**-367** %	**345** %	**25** %	**NA**	**0** %	**344** %

**** 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)	$7,475.6	$ 119.5	$ 7,595.1	$ 92.3	$ 217.4	$ 309.7	$7,904.8
Less: Asset Retirement Costs	(148.9)	(31.0)	(179.9)	(14.0)	(1.7)	(15.7)	(195.6)
Acquisition Cost of Proved Properties	(138.8)	(0.3)	(139.1)	-	-	-	(139.1)
Total Exploration & Development Expenditures for Drilling Only (Non-GAAP) (a)	**$7,187.9**	**$ 88.2**	**$ 7,276.1**	**$ 78.3**	**$ 215.7**	**$ 294.0**	**$7,570.1**
Total Costs Incurred in Exploration and Development Activities (GAAP)	$7,475.6	$ 119.5	$ 7,595.1	$ 92.3	$ 217.4	$ 309.7	$7,904.8
Less: Asset Retirement Costs	(148.9)	(31.0)	(179.9)	(14.0)	(1.7)	(15.7)	(195.6)
Total Exploration & Development Expenditures (Non-GAAP) (b)	**$7,326.7**	**$ 88.5**	**$ 7,415.2**	**$ 78.3**	**$ 215.7**	**$ 294.0**	**$7,709.2**
Total Expenditures (GAAP)	$8,200.6	$ 120.9	$ 8,321.5	$ 92.5	$ 217.9	$ 310.4	$8,631.9
Less: Asset Retirement Costs	(148.9)	(31.0)	(179.9)	(14.0)	(1.7)	(15.7)	(195.6)
Non-Cash Acquisition Costs of Unproved Properties	(5.0)	-	(5.0)	-	-	-	(5.0)
Total Cash Expenditures							

(Non-GAAP)	**$8,046.7**	**$ 89.9**	**$ 8,136.6**	**$ 78.5**	**$ 216.2**	**$ 294.7**	**$8,431.3**
Net Proved Reserve Additions From All Sources - Oil Equivalents (MMBoe)							
Revisions due to price (c)	51.9	0.3	52.2	-	-	-	52.2
Revisions other than price	45.9	1.0	46.9	2.2	(0.7)	1.5	48.4
Purchases in place	14.4	-	14.4	-	-	-	14.4
Extensions, discoveries and other additions (d)	517.6	-	517.6	0.8	0.8	1.6	519.2
Total Proved Reserve Additions (e)	**629.8**	**1.3**	**631.1**	**3.0**	**0.1**	**3.1**	**634.2**
Sales in place	(14.7)	(21.6)	(36.3)	-	-	-	(36.3)
Net Proved Reserve Additions From All Sources (f)	**615.1**	**(20.3)**	**594.8**	**3.0**	**0.1**	**3.1**	**597.9**
Production (g)	**190.1**	**6.0**	**196.1**	**22.4**	**0.6**	**23.0**	**219.1**
RESERVE REPLACEMENT COSTS ($ / Boe)							
Total Drilling, Before Revisions (a / d)	**$ 13.89**	**NA**	**$ 14.06**	**$ 97.88**	**$269.63**	**$183.75**	**$ 14.58**
All-in Total, Net of Revisions (b / e)	**$ 11.63**	**$ 68.08**	**$ 11.75**	**$ 26.10**	**NA**	**$ 94.84**	**$ 12.16**
All-in Total, Excluding Revisions Due to Price (b / (e - c))	**$ 12.68**	**$ 88.50**	**$ 12.81**	**$ 26.10**	**NA**	**$ 94.84**	**$ 13.25**
RESERVE REPLACEMENT							
Drilling Only (d / g)	**272 %**	**0 %**	**264 %**	**4 %**	**133 %**	**7 %**	**237 %**
All-in Total, Net of Revisions & Dispositions (f / g)	**324 %**	**-338 %**	**303 %**	**13 %**	**17 %**	**13 %**	**273 %**
All-in Total, Excluding Revisions Due to Price ((f - c) / g)	**296 %**	**-343 %**	**277 %**	**13 %**	**17 %**	**13 %**	**249 %**
Net Proved Reserve Additions From All Sources - Liquids (MMBbls)							
Revisions	55.7	(0.3)	55.4	0.1	(0.1)	-	55.4
Purchases in place	11.5	-	11.5	-	-	-	11.5
Extensions, discoveries and other additions (h)	411.3	-	411.3	-	-	-	411.3
Total Proved Reserve Additions	**478.5**	**(0.3)**	**478.2**	**0.1**	**(0.1)**	**-**	**478.2**
Sales in place	(6.0)	(8.5)	(14.5)	-	-	-	(14.5)
Net Proved Reserve Additions From All Sources (i)	**472.5**	**(8.8)**	**463.7**	**0.1**	**(0.1)**	**-**	**463.7**
Production (j)	**131.9**	**2.4**	**134.3**	**0.4**	**-**	**0.4**	**134.7**

RESERVE REPLACEMENT - LIQUIDS							
Drilling Only (h / j)	**312 %**	**0 %**	**306 %**	**0 %**	**NA**	**0 %**	**305 %**
All-in Total, Net of Revisions & Dispositions (i / j)	**358 %**	**-367 %**	**345 %**	**25 %**	**NA**	**0 %**	**344 %**

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 at February 16, 2015, 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)
2015 (1)		
January 2015 (closed)	47,000	$ 91.22
February 1, 2015 through June 30, 2015	47,000	91.22
July 1, 2015 through December 31, 2015	10,000	89.98

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional six-month periods. Options covering a notional volume of 37,000 Bbld are exercisable on June 30, 2015. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 37,000 Bbld at an average price of $91.56 per barrel for each month during the period July 1, 2015 through December 31, 2015.

NATURAL GAS DERIVATIVE CONTRACTS

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2015 (2)		
January 1, 2015 through February 28, 2015 (closed)	235,000	$ 4.47
March 2015	225,000	4.48
April 2015	195,000	4.49
May 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 175,000 MMBtud at an average price of $4.51 per MMBtu for each month during the period March 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.
DIRECT AFTER-TAX RATE OF RETURN (ATROR)

The calculation of our direct after-tax rate of return (ATROR) with respect to our capital expenditure program for a particular play or well is based on the estimated proved reserves ("net" to EOG's interest) for all wells in such play or such well (as the case may be), the estimated present value of the future net cash flows from such reserves (for which we utilize certain assumptions regarding future commodity prices and operating costs) and our direct net costs incurred in drilling or acquiring (as the case may be) such wells or well (as the case may be). As such, our direct ATROR with respect to our capital expenditures for a particular play or well cannot be calculated from our consolidated financial statements.

Direct ATROR

Based on Cash Flow and Time Value of Money
- Estimated future commodity prices and operating costs
- Costs incurred to drill and complete a well, including facilities

Excludes Indirect Capital
- Gathering and Processing and other Midstream
- Land, Seismic, Geological and Geophysical

Payback ~12 Months on 100% Direct ATROR Wells
First Five Years ~1/2 EUR Produced but ~3/4 of NPV Captured
ATROR of Drilling Program Has Been Rising

Return on Equity / Return on Capital Employed

Based on GAAP Accrual Accounting
Includes All Indirect Capital and Growth Capital for Infrastructure
- Eagle Ford, Bakken, Permian Facilities
- Gathering and Processing

Includes Legacy Gas Capital and Capital from Mature Wells
Has Been Increasing Due to Increasing Direct ATROR of Drilling Program

EOG RESOURCES, INC.

QUANTITATIVE RECONCILIATION OF AFTER-TAX INTEREST EXPENSE, NET (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, NET (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, Net (GAAP), Net Income (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Interest Expense, Net (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, Net, 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.

	2014	2013	2012
Return on Capital Employed (ROCE) (Non-GAAP)			
Interest Expense, Net (GAAP)	$ 201	$ 235	
Tax Benefit Imputed (based on 35%)	(70)	(82)	
After-Tax Interest Expense, Net (Non-GAAP) - (a)	$ 131	$ 153	
Net Income (GAAP) - (b)	$ 2,915	$ 2,197	
Add: After-Tax Mark-to-Market Commodity Derivative Contracts Impact	(515)	182	
Add: Impairments of Certain Assets, Net of Tax	553	4	
Add: Tax Expense Related to the Repatriation of Accumulated Foreign Earnings in Future Years	250	-	
Less: Net Gains on Asset Dispositions, Net of Tax	(487)	(137)	
Adjusted Net Income (Non-GAAP) - (c)	$ 2,716	$ 2,246	
Total Stockholders' Equity - (d)	$ 17,713	$ 15,418	$ 13,285
Average Total Stockholders' Equity * - (e)	$ 16,566	$ 14,352	
Current and Long-Term Debt (GAAP) - (f)	$ 5,910	$ 5,913	$ 6,312
Less: Cash	(2,087)	(1,318)	(876)
Net Debt (Non-GAAP) - (g)	$ 3,823	$ 4,595	$ 5,436
Total Capitalization (GAAP) - (d) + (f)	$ 23,623	$ 21,331	$ 19,597
Total Capitalization (Non-GAAP) - (d) + (g)	$ 21,536	$ 20,013	$ 18,721
Average Total Capitalization (Non-GAAP) * - (h)	$ 20,775	$ 19,367	
ROCE (GAAP Net Income) - [(a) + (b)] / (h)	**14.7** %	**12.1** %	
ROCE (Non-GAAP Adjusted Net Income) - [(a) + (c)] / (h)	**13.7** %	**12.4** %	

Return on Equity (ROE) (Non-GAAP)

ROE (GAAP Net Income) - (b) / (e)	**17.6 %**	**15.3 %**
ROE (Non-GAAP Adjusted Net Income) - (c) / (e)	**16.4 %**	**15.6 %**

* Average for the current and immediately preceding year

EOG RESOURCES, INC.
FIRST QUARTER AND FULL YEAR 2015 FORECAST AND BENCHMARK COMMODITY PRICING

(a) First Quarter and Full Year 2015 Forecast

The forecast items for the first quarter and full year 2015 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 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 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 2015			Full Year 2015		
Daily Production						
Crude Oil and Condensate Volumes (MBbld)						
United States	287.0	-	297.0	264.0	-	293.0
Trinidad	0.5	-	0.9	0.7	-	0.9
Other International	0.1	-	0.3	6.0	-	11.0
Total	287.6	-	298.2	270.7	-	304.9
Natural Gas Liquids Volumes (MBbld)						
Total	75.0	-	83.0	68.0	-	88.0
Natural Gas Volumes (MMcfd)						
United States	880	-	910	850	-	890
Trinidad	330	-	360	330	-	360
Other International	24	-	30	27	-	33
Total	1,234	-	1,300	1,207	-	1,283
Crude Oil Equivalent Volumes (MBoed)						
United States	508.7	-	531.7	473.7	-	529.3
Trinidad	55.5	-	60.9	55.7	-	60.9
Other International	4.1	-	5.3	10.5	-	16.5
Total	568.3	-	597.9	539.9	-	606.7
Operating Costs						
Unit Costs ($/Boe)						
Lease and Well	$ 6.35	-	$ 6.65	$ 6.35	-	$ 6.85
Transportation Costs	$ 4.60	-	$ 4.90	$ 4.60	-	$ 5.00
Depreciation, Depletion and Amortization	$ 17.35	-	$ 17.75	$ 17.70	-	$ 18.30
Expenses ($MM)						
Exploration, Dry Hole and Impairment	$ 130	-	$ 150	$ 525	-	$ 575
General and Administrative	$ 90	-	$ 100	$ 375	-	$ 400
Gathering and Processing	$ 40	-	$ 46	$ 155	-	$ 185
Capitalized Interest	$ 14	-	$ 15	$ 55	-	$ 60
Net Interest	$ 49	-	$ 50	$ 200	-	$ 205

Taxes Other Than Income (% of Wellhead Revenue)		6.5	% -		7.0	%		6.3	% -		6.9	%
Income Taxes												
Effective Rate		22	% -		27	%		23	% -		28	%
Current Taxes ($MM)	$	30	-	$	45		$	140	-	$	160	
Capital Expenditures ($MM) - (Excluding Acquisitions)												
Exploration and Development, Excluding Facilities							$	3,950	-	$	4,050	
Exploration and Development Facilities							$	580	-	$	620	
Gathering, Processing and Other							$	370	-	$	430	
Pricing - (Refer to Benchmark Commodity Pricing in text)												
Crude Oil and Condensate ($/Bbl)												
Differentials												
United States - above (below) WTI	$	(1.60)	-	$	0.00		$	(2.00)	-	$	0.00	
Trinidad - above (below) WTI	$	(10.50)	-	$	(9.50)		$	(12.00)	-	$	(8.00)	
Natural Gas Liquids												
Realizations as % of WTI		31	% -		35	%		30	% -		36	%
Natural Gas ($/Mcf)												
Differentials												
United States - above (below) NYMEX Henry Hub	$	(0.80)	-	$	(0.35)		$	(0.85)	-	$	(0.35)	
Realizations												
Trinidad	$	2.80	-	$	3.60		$	2.80	-	$	3.60	
Other International	$	3.15	-	$	3.75		$	3.25	-	$	3.85	

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