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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

or

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

Commission file number: 1-9743

EOG RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**47-0684736**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2015: $47,957 million.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $0.01 per share, 549,883,390 shares outstanding as of February 18, 2016.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2016 Annual Meeting of Stockholders, to be filed within 120 days after December 31, 2015, are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

PART I

ITEM 1. *Business*

General

EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively, EOG), explores for, develops, produces and markets crude oil and natural gas primarily in major producing basins in the United States of America (United States or U.S.), The Republic of Trinidad and Tobago (Trinidad), the United Kingdom (U.K.), The People's Republic of China (China), Canada and, from time to time, select other international areas. EOG's principal producing areas are further described in "Exploration and Production" below. EOG's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports are made available, free of charge, through EOG's website, as soon as reasonably practicable after such reports have been filed with the United States Securities and Exchange Commission (SEC). EOG's website address is www.eogresources.com. Information on our website is not incorporated by reference into, and does not constitute a part of, this report.

At December 31, 2015, EOG's total estimated net proved reserves were 2,118 million barrels of oil equivalent (MMBoe), of which 1,098 million barrels (MMBbl) were crude oil and condensate reserves, 383 MMBbl were natural gas liquids (NGLs) reserves and 3,825 billion cubic feet, or 637 MMBoe, were natural gas reserves (see Supplemental Information to Consolidated Financial Statements). At such date, approximately 97% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States and 3% in Trinidad. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet (Mcf) of natural gas.

As of December 31, 2015, EOG employed approximately 2,760 persons, including foreign national employees.

EOG's business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG is focused on cost-effective utilization of advanced technology associated with three-dimensional seismic and microseismic data, the development of reservoir simulation models, the use of improved drill bits, completion technologies for horizontal drilling and formation evaluation. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks associated with all aspects of oil and gas exploration, development and exploitation. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG's strategy.

With respect to information on EOG's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by EOG's working interest in the wells or acreage.

Business Segments

EOG's operations are all crude oil and natural gas exploration and production related. For financial information about our reportable segments (including financial information by segment geographic area), see Note 11 to Consolidated Financial Statements. For information regarding the risks associated with EOG's foreign operations, see ITEM 1A, Risk Factors.

Exploration and Production

United States Operations

EOG's operations are focused in most of the productive basins in the United States with a current focus on crude oil and, to a lesser extent, liquids-rich natural gas plays.

At December 31, 2015, on a crude oil equivalent basis, 53% of EOG's net proved reserves in the United States were crude oil and condensate, 19% were NGLs and 28% were natural gas. The majority of these reserves are in long-lived fields with well-established production characteristics. EOG believes that opportunities exist to increase production through continued development in and around many of these fields and through the utilization of applicable technologies. EOG also maintains an active exploration program designed to extend fields and add new trends and resource plays to its already broad portfolio. The following is a summary of significant developments during 2015 and certain 2016 plans for EOG's United States operations.

The Eagle Ford continues to prove itself as a world-class oil field having produced in excess of 1.5 billion barrels of crude oil and condensate. With approximately 549,000 of its 608,000 total net acres in the prolific oil window, EOG continues to be the largest crude oil producer in the Eagle Ford with cumulative gross production in excess of 285 MMBbl of oil. EOG completed 329 net wells in 2015 and net production averaged approximately 209 thousand barrels per day (MBbld) of crude oil and condensate and NGLs, an increase of 3% over 2014. The combination of self-sourced sand, dedicated frac crews and other services along with continuous well optimization programs have made this play the centerpiece of EOG's portfolio. In 2016, EOG expects to complete approximately 150 net wells, continue to improve well productivity and reduce drilling and completion costs as well as operating expenses.

In the Permian Basin, EOG completed 74 net wells primarily in the Leonard, Wolfcamp, and Second Bone Spring Sand plays during 2015, and evaluated multiple development concepts across these liquids-rich plays. In the Delaware Basin Wolfcamp Shale play, where it has approximately 168,000 net acres, EOG tested 500-foot well spacing in both the crude oil and combo portions of this play with positive results. The success of the 2015 Delaware Basin Wolfcamp program was due to refined targeting, high-density stimulations and cost reductions, which will make the play a focal point of EOG's 2016 Permian Basin program. In the Second Bone Spring Sand play, where it holds approximately 111,000 net acres, EOG tested multiple target zones and well spacing as close as 550 feet. With over 1,000 estimated remaining net drilling locations, this high-return oil play is another integral part of EOG's Permian Basin portfolio. In the Leonard Shale play, EOG has approximately 93,000 net acres and continued development at 300- to 500- foot well spacing. Additionally, EOG has approximately 71,000 net acres in the Wolfcamp Shale within the Midland Basin. Net production in the Permian Basin for 2015 averaged approximately 43 MBbld of crude oil and condensate and NGLs, an increase of 30% over 2014. Net natural gas production increased 27% to approximately 108 million cubic feet per day (MMcfd). EOG holds approximately 415,000 net acres throughout the Permian Basin. In 2016, activity will be focused primarily in the Delaware Basin Wolfcamp, Second Bone Spring Sand and Leonard plays by completing approximately 75 net wells.

During 2015, the Rocky Mountain area experienced reduced activity levels due to lower commodity prices but yielded consistent results. In 2015, EOG continued infill drilling on its crude oil acreage in the Williston Basin Bakken core, completing 25 net wells. The 2015 development program also included completing 10 net Codell formation wells in the DJ Basin and 13 net wells in the Turner, Parkman and Niobrara formations in the Powder River Basin. Infrastructure improvements allowed for a substantial reduction in lease operating expenses and a much higher natural gas recovery. Improved efficiencies, lower service company costs both for drilling and completions and lower lease operating expenses resulted in more profitable wells in this challenging price environment. Net production for the entire Rocky Mountain area for 2015 averaged approximately 65 MBbld of crude oil and condensate and NGLs. In 2016, EOG plans to complete approximately 35 net wells, primarily in the Powder River and Williston Basins. EOG holds approximately 985,000 net acres in the Rocky Mountain area.

In the Upper Gulf Coast region, EOG completed six net wells during 2015 and net production averaged approximately 54 MMcfd of natural gas and approximately 4 MBbld of crude oil and condensate and NGLs. In 2016, EOG will continue to defer dry gas drilling in the Haynesville Shale, while working to maintain base production and continue its liquids exploration program. EOG holds approximately 529,000 net acres in the Upper Gulf Coast region and plans to complete approximately five net wells in 2016.

In the Mid-Continent area, EOG continued its successful horizontal exploitation of the Pennsylvanian sandstones in the Anadarko Basin, completing five net wells in 2015. During 2015, EOG's net production averaged approximately 6 MBbld of crude oil and condensate and NGLs and approximately 29 MMcfd of natural gas. EOG holds approximately 250,000 net acres throughout the Mid-Continent area and expects to continue its exploration program in 2016.

During 2015, EOG performed limited development of its liquids-rich Barnett Shale Combo play in the Fort Worth Basin, completing six net wells. In 2015, net production in the Barnett Shale averaged approximately 27 MBbld of crude oil and condensate and NGLs and approximately 272 MMcfd of natural gas. For 2016, EOG will focus on maintaining base production. EOG currently holds approximately 351,000 net acres in the Barnett Shale.

In the South Texas area, total net production during 2015 averaged approximately 6 MBbld of crude oil and condensate and NGLs and approximately 66 MMcfd of natural gas. EOG completed seven net wells with activity focused in San Patricio, Kleberg and Jim Wells counties. In 2016, EOG expects to complete approximately five net wells in the Frio and Vicksburg trends, where it holds approximately 272,000 net acres. Exploration efforts will continue in this region, primarily focusing on liquids-rich hydrocarbons.

Net production in the Marcellus Shale for 2015 averaged approximately 24 MMcfd of natural gas. EOG currently holds approximately 200,000 net acres with Marcellus and Utica Shale potential.

EOG has agreements with certain crude oil refining companies to deliver an average of 58 MBbld and 9 MBbld of crude oil in 2016 and 2017, respectively, to certain refineries. EOG intends to fulfill these crude oil delivery obligations with its Eagle Ford production.

At December 31, 2015, EOG held approximately 2.0 million net undeveloped acres in the United States.

During 2015, EOG continued the expansion of its gathering and processing activities in the Eagle Ford in South Texas, the Bakken and Three Forks plays in North Dakota and the Permian Basin in West Texas and New Mexico. At December 31, 2015, EOG-owned natural gas processing capacity in the Eagle Ford and Barnett Shale totaled 305 MMcfd and 180 MMcfd, respectively.

Also during 2015, EOG continued to use its crude oil loading facility near Stanley, North Dakota, to transport its Williston Basin crude oil production. During 2015, EOG loaded 81 unit trains (each unit train typically consists of 100 cars and has a total aggregate capacity of approximately 70,000 barrels of crude oil) with crude oil for transport to St. James, Louisiana and Stroud, Oklahoma. EOG has net unloading capacity of 100 MBbld and 90 MBbld at St. James and Stroud, respectively. During 2015, a total of 18 crude oil unit trains carrying EOG production were received at the crude oil unloading facility in St. James, Louisiana, which provides access to one of the key markets in the U.S., where sales are based upon the Light Louisiana Sweet (LLS) crude oil index. In addition, EOG utilized its Stroud, Oklahoma, crude oil unloading facility and pipeline to transport 63 unit trainloads of crude oil to the Cushing, Oklahoma trading hub. EOG believes that its marketing and related logistics processes, including crude-by-rail facilities, provide a competitive advantage, giving EOG the flexibility to direct its crude oil shipments via rail car to the most favorable markets. EOG expects to utilize its crude-by-rail network when it is advantageous.

EOG operates its own sand mine and sand processing plants in Hood County, Texas, to reduce costs and to help fulfill EOG's sand needs for its well completion operations in Texas. Additionally, EOG owns a second Hood County sand processing plant, which processes raw sand from Wisconsin, and sand sourced from the north Texas area, as needed.

In 2015, EOG continued to process sand from its Chippewa Falls, Wisconsin, sand plant on an as-needed basis.

EOG placed in service an additional sand unloading facility in Loving, New Mexico, during the first quarter of 2015 to support well completions in the Delaware Basin.

During 2015, EOG shipped the equivalent of 173 sand unit trains from various sources, to support well completions in the Eagle Ford and other plays.

Operations Outside the United States

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

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

- holds an 80% working interest in the exploration and production license covering the South East Coast Consortium (SECC) Block offshore Trinidad, except in the Deep Ibis area in which EOG's working interest decreased as a result of a third-party farm-out agreement;
- holds an 80% working interest in the exploration and production license covering the Pelican Field and its related facilities;
- holds a 50% working interest in the exploration and production licenses covering the Sercan Area (formerly known as the EMZ Area) offshore Trinidad;
- holds a 100% working interest in a production sharing contract with the Government of Trinidad and Tobago for each of the Modified U(a) Block, Modified U(b) Block and Block 4(a);
- owns a 12% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited; and
- owns a 10% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited.

Several fields in the SECC Block, Modified U(a) Block, Modified U(b) Block, Block 4(a) and the Sercan Area have been developed and are producing natural gas and crude oil and condensate. Natural gas from EOG's Trinidad operations currently is sold under various contracts with the National Gas Company of Trinidad and Tobago Limited and its subsidiary (NGC). Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago Limited (Petrotrin). In 2015, EOG's net production from Trinidad averaged approximately 349 MMcfd of natural gas and approximately 0.9 MBbld of crude oil and condensate.

EOG completed three net wells in 2015, finishing its SECC Block and Modified U(b) Block drilling program which was initiated in 2014.

In 2016, it is anticipated that EOG's Trinidad operations will supply approximately 430 MMcfd (290 MMcfd, net) of natural gas from its existing proved reserves. All of the natural gas produced from EOG's Trinidad operations in 2016 is expected to be supplied to NGC under various contracts with NGC. All crude oil and condensate produced from EOG's Trinidad operations in 2016 is expected to be supplied to Petrotrin under various contracts with Petrotrin. In 2016, EOG expects to complete one net well and install infrastructure in the Sercan Area.

At December 31, 2015, EOG held approximately 40,000 net undeveloped acres in Trinidad.

United Kingdom. EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), owns a 25% non-operating working interest in a portion of Block 49/16a, located in the Southern Gas Basin of the North Sea. During 2015, a limited amount of production continued from the Valkyrie field in this block. Production ceased at the end of the third quarter of 2015, and decommissioning is planned for the fourth quarter of 2016.

In 2007, EOGUK was awarded a license for two blocks in the East Irish Sea – Blocks 110/7b and 110/12a. In 2009, EOGUK drilled a successful exploratory well in the East Irish Sea Block 110/12a. The well, in which EOGUK has a 100% working interest, was an oil discovery and was designated the Conwy field. During 2012 and 2013, the Conwy production platform and pipelines were installed. Modifications to the nearby third-party owned Douglas platform, which will be used to process Conwy production, began in 2013 and continued throughout 2014 and 2015. First production from the Conwy field is anticipated in March 2016.

In 2015, production averaged less than 0.1 MMcfd of natural gas, net, in the United Kingdom.

At December 31, 2015, EOG held approximately 7,000 net undeveloped acres in the United Kingdom.

China. In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuan Zhong Block exploration area in the Sichuan Basin, Sichuan Province, China. In October 2008, EOG obtained the rights to shallower zones on the acquired acreage. In 2015, EOG drilled four wells and completed three wells, one of which was drilled in 2014, in the Sichuan Basin, Sichuan Province, China. The successful completions extended the Shaximiao development in the Chuan Zhong Block and provides additional opportunities in the future.

In 2015, production averaged approximately 14 MMcfd of natural gas, net, in China.

Canada. During 2014, EOG sold all of its assets in Manitoba and the majority of its assets in Alberta in two separate transactions that closed on or about December 1, 2014. EOG divested 1.3 million gross acres (1.1 million net), 97 percent of which were in Alberta. Of the approximate 5,800 net producing wells sold, 5,155 were natural gas. In 2015, net production averaged approximately 15 MMcfd of natural gas and less than 0.1 MBbld of NGLs.

Argentina. EOG's activity in Argentina is focused on the Vaca Muerta oil shale formation in the Neuquén Province. Management is currently evaluating options for its investment.

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

Marketing

In 2015, EOG's wellhead crude oil and condensate production was sold into local markets or transported either by pipeline, truck or EOG's crude-by-rail assets to downstream markets. In each case, the price received was based on market prices at that specific sales point or based on the price index applicable for that location. Major U.S. sales areas included the Midwest, the Permian Basin, Cushing, Oklahoma, St. James, Louisiana, and other points along the U.S. Gulf Coast. In 2016, the pricing mechanism for such production is expected to remain the same.

In 2015, EOG processed certain of its natural gas production, either at EOG-owned facilities or at third-party facilities, extracting NGLs. NGLs were sold at prevailing market prices. In 2016, the pricing mechanism for such production is expected to remain the same.

In 2015, EOG's United States and Canada wellhead natural gas production was sold into local markets or transported by pipeline to downstream markets. Pricing was based on the spot market at the ultimate sales point. In 2016, the pricing mechanism for such production is expected to remain the same.

In 2015, a large majority of the wellhead natural gas volumes from Trinidad were sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes were sold under a contract at prices partially dependent on United States Henry Hub market prices. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2016.

In 2015, all wellhead natural gas volumes from the U.K. were sold on the spot market. In December 2014, EOG put in place arrangements to market and sell its U.K. wellhead crude oil production from the Conwy field, which is anticipated to begin in March 2016. The crude oil sales will be based on a Dated Brent price or other market prices, as applicable.

In 2015, all wellhead natural gas volumes from China were sold at regulated prices based on the purchaser's pipeline sales volumes to various local market segments. The pricing mechanism for production in China is expected to remain the same in 2016.

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

During 2015, two purchasers each accounted for more than 10% of EOG's total wellhead crude oil and condensate, NGL and natural gas revenues and gathering, processing and marketing revenues. Both purchasers are in the crude oil refining industry. EOG does not believe that the loss of any single purchaser would have a material adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of, and average prices for, crude oil and condensate, NGLs and natural gas. The table also presents crude oil equivalent volumes which are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 Mcf of natural gas for each of the years ended December 31, 2015, 2014 and 2013.

Year Ended December 31	**2015**	**2014**	**2013**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States:			
Eagle Ford	181.7	178.0	122.3
Other	101.6	104.0	89.8
United States	283.3	282.0	212.1
Trinidad	0.9	1.0	1.2
Other International (2)	0.2	5.9	7.1
Total	**284.4**	**288.9**	**220.4**
Natural Gas Liquids Volumes (MBbld) (1)			
United States:			
Eagle Ford	27.2	24.7	18.6
Other	49.7	55.0	45.7
United States	76.9	79.7	64.3
Other International (2)	0.1	0.6	0.9
Total	**77.0**	**80.3**	**65.2**
Natural Gas Volumes (MMcfd) (1)			
United States:			
Eagle Ford	179	164	115
Other	707	756	793
United States	886	920	908
Trinidad	349	363	355
Other International (2)	30	70	84
Total	**1,265**	**1,353**	**1,347**
Crude Oil Equivalent Volumes (MBoed) (3)			
United States:			
Eagle Ford	238.8	230.0	160.2
Other	269.1	285.0	267.7
United States	507.9	515.0	427.9
Trinidad	59.1	61.5	60.4
Other International (2)	5.2	18.2	21.8
Total	**572.2**	**594.7**	**510.1**
Total MMBoe (3)	**208.9**	**217.1**	**186.2**

Year Ended December 31	2015	2014	2013
Average Crude Oil and Condensate Prices ($/Bbl) [4]			
United States	$ 47.55	$ 92.73	$ 103.81
Trinidad	39.51	84.63	90.30
Other International [2]	57.32	86.75	87.08
Composite	**47.53**	**92.58**	**103.20**
Average Natural Gas Liquids Prices ($/Bbl) [4]			
United States	$ 14.50	$ 31.84	$ 32.46
Other International [2]	4.61	40.73	39.45
Composite	**14.49**	**31.91**	**32.55**
Average Natural Gas Prices ($/Mcf) [4]			
United States	$ 1.97	$ 3.93	$ 3.32
Trinidad	2.89	3.65	3.68
Other International [2]	5.05	4.40	3.39
Composite	**2.30**	**3.88**	**3.42**

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Other International includes EOG's United Kingdom, China, Canada and Argentina operations.
(3) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, NGLs and natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.
(4) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

Competition

EOG competes with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services, and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce, market and transport crude oil and natural gas. In addition, many of EOG's competitors have financial and other resources substantially greater than those EOG possesses and have established strategic long-term positions and strong governmental relationships in countries in which EOG may seek new or expanded entry. As a consequence, EOG may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, many of EOG's larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Regulation

United States Regulation of Crude Oil and Natural Gas Production. Crude oil and natural gas production operations are subject to various types of regulation, including regulation in the United States by federal and state agencies.

United States legislation affecting the oil and gas industry is under constant review for amendment or expansion. In addition, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations applicable to the oil and gas industry. Such rules and regulations, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas through restrictions on flaring, require surety bonds for various exploration and production operations and regulate the calculation and disbursement of royalty payments (for federal and state leases), production taxes and ad valorem taxes.

A portion of EOG's oil and gas leases in New Mexico, North Dakota, Utah, Wyoming and the Gulf of Mexico, as well as in other areas, are granted by the federal government and administered by the Bureau of Land Management (BLM) and/or the Bureau of Indian Affairs (BIA) or, in the case of offshore leases (which, for EOG, are de minimis), by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), all federal agencies. Operations conducted by EOG on federal oil and gas leases must comply with numerous additional statutory and regulatory restrictions and, in the case of leases relating to tribal lands, certain tribal environmental and permitting requirements and employment rights regulations. In addition, the U.S. Department of the Interior (via various of its agencies, including the BLM, the BIA and the Office of Natural Resources Revenue) has certain authority over our calculation and payment of royalties, bonuses, fines, penalties, assessments and other revenues related to our federal and tribal oil and gas leases.

BLM, BIA and BOEM leases contain relatively standardized terms requiring compliance with detailed regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act (which are subject to change by the BOEM or BSEE). Under certain circumstances, the BLM, BIA, BOEM or BSEE (as applicable) may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect EOG's interests.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938, as amended (NGA), and the Natural Gas Policy Act of 1978. These statutes are administered by the Federal Energy Regulatory Commission (FERC). Effective January 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, may be subject in the future to greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and NGLs by EOG are made at unregulated market prices.

EOG owns certain gathering and/or processing facilities in the Permian Basin in West Texas and New Mexico, the Barnett Shale in North Texas, the Bakken and Three Forks plays in North Dakota, and the Eagle Ford in South Texas. State regulation of gathering and processing facilities generally includes various safety, environmental and, in some circumstances, nondiscrimination requirements with respect to the provision of gathering and processing services, but does not generally entail rate regulation. EOG's gathering and processing operations could be materially and adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's gathering and processing operations also may be, or become, subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, such legislation might have on its operations and financial condition, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future legislative and regulatory changes.

EOG also owns crude oil rail loading facilities in North Dakota and Texas, crude oil rail unloading facilities in Oklahoma and Louisiana and crude oil truck unloading facilities in certain of its U.S. plays. Regulation of such facilities is conducted at the state and federal levels and generally includes various safety, environmental, permitting and packaging/labeling requirements. Additional regulation pertaining to these matters is considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, any such new regulations might have on its crude-by-rail operations and the transportation of its crude oil production by truck, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future regulatory changes.

Proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the state legislatures, the FERC and federal, state and local regulatory commissions, agencies, councils and courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the oil and gas industry historically has been very heavily regulated; therefore, there is no assurance that the approach currently being followed by such legislative bodies and regulatory commissions, agencies, councils and courts will remain unchanged.

Environmental Regulation - United States. EOG is subject to various federal, state and local laws and regulations covering the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations affect EOG's operations and costs as a result of their effect on crude oil and natural gas exploration, development and production operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements.

In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. EOG also could incur costs related to the clean-up of third-party sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such third-party sites. In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG previously owned or currently owns an interest, but was or is not the operator. Moreover, EOG is subject to the U.S. Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions and may in the future, as discussed further below, be subject to federal, state and local laws and regulations regarding hydraulic fracturing.

Compliance with environmental laws and regulations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, EOG is unable to predict the ultimate cost of compliance or the ultimate effect on EOG's operations, financial condition and results of operations.

Climate Change - United States. Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, recent U.S. EPA rulemaking may result in the regulation of GHG emissions as pollutants under the federal Clean Air Act. Also, in December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020.

EOG believes that its strategy to reduce GHG emissions throughout its operations is in the best interest of the environment and is a generally good business practice. EOG has developed a system that is utilized in calculating GHG emissions from its operating facilities. This emissions management system calculates emissions based on recognized regulatory methodologies, where applicable, and on commonly accepted engineering practices. EOG reports GHG emissions for facilities covered under the U.S. EPA's Mandatory Reporting of Greenhouse Gases Rule published in 2009.

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

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

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. In March 2015, the BLM issued new regulations applicable to hydraulic fracturing activities on federal and Indian lands, including requirements for chemical disclosure, wellbore integrity and handling of flowback and produced water. In addition, there have been various other proposals to regulate hydraulic fracturing at the federal level. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements, additional operating and compliance costs and additional operating restrictions. In April 2012, the U.S. EPA issued regulations specifically applicable to the oil and gas industry that will require operators to significantly reduce volatile organic compounds (VOC) emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The U.S. EPA also issued regulations that establish standards for VOC emissions from several types of equipment, including storage tanks, compressors, dehydrators, and valves and sweetening units at gas processing plants. In addition, the U.S. EPA recently proposed regulations that would require operators to reduce methane and VOC emissions from crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations.

In addition to these federal regulations, some state and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; disclosure of the chemical additives used in hydraulic fracturing operations; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Such federal, state and local permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

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

Other International Regulation. EOG's exploration and production operations outside the United States are subject to various types of regulations, including environmental regulations, imposed by the respective governments of the countries in which EOG's operations are conducted, and may affect EOG's operations and costs of compliance within those countries. EOG currently has operations in Trinidad, the United Kingdom, China, Canada and Argentina. EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations. EOG will continue to review the risks to its business and operations associated with all environmental matters, including climate change and hydraulic fracturing. In addition, EOG will continue to monitor and assess any new policies, legislation, regulations and treaties in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Other Regulation. EOG has sand mining and processing operations in Texas and Wisconsin, which support EOG's exploration and development operations. EOG's sand mining operations are subject to regulation by the federal Mine Safety and Health Administration (in respect of safety and health matters) and by state agencies (in respect of air permitting and other environmental matters). The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

Other Matters

Energy Prices. EOG is a crude oil and natural gas producer and is impacted by changes in prices of crude oil and condensate, NGLs and natural gas. Crude oil and condensate and NGL production comprised a larger portion of EOG's production mix in 2015 than in prior years. Average crude oil and condensate prices received by EOG for production in the United States decreased 49% in 2015, decreased 11% in 2014 and increased 6% in 2013, each as compared to the immediately preceding year. Average NGL prices received by EOG for production in the United States decreased 54% in 2015, 2% in 2014 and 8% in 2013, each as compared to the immediately preceding year. During the last three years, average United States wellhead natural gas prices have fluctuated, at times rather dramatically. These fluctuations resulted in a 50% decrease in the average wellhead natural gas price received by EOG for production in the United States in 2015, an 18% increase in 2014 and a 32% increase in 2013, each as compared to the immediately preceding year. In addition, as of February 12, 2016, the average 2016 U.S. New York Mercantile Exchange (NYMEX) crude oil and natural gas prices were $34.97 per barrel and $2.23 per million British thermal units, respectively, representing declines of 28% and 17%, respectively, from the average NYMEX prices in 2015. Due to the many uncertainties associated with the world political environment (for example, the actions of other crude oil exporting nations, including the

Organization of Petroleum Exporting Countries), the global supply of and demand for crude oil and the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors, EOG is unable to predict what changes may occur in prices of crude oil and condensate, NGLs and natural gas in the future. For additional discussion regarding changes in crude oil and natural gas prices and the risks that such changes may present to EOG, see ITEM 1A, Risk Factors.

Based on EOG's tax position, EOG's price sensitivity in 2016 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately $65 million for net income and $81 million for cash flows from operating activities. Including the impact of EOG's 2016 natural gas derivative contracts (exclusive of options) and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2016 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $15 million for net income and $18 million for cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts at February 25, 2016, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions.

Risk Management. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in prices of crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. See Note 12 to Consolidated Financial Statements. For a summary of EOG's financial commodity derivative contracts at February 25, 2016, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions.

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

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

In addition to the above-described risks, EOG's operations outside the United States are subject to certain risks, including the risk of increases in taxes and governmental royalties, changes in laws and policies governing the operations of foreign-based companies, expropriation of assets, unilateral or forced renegotiation or modification of existing contracts with governmental entities, currency restrictions and exchange rate fluctuations. Please refer to ITEM 1A, Risk Factors, for further discussion of the risks to which EOG is subject with respect to its operations outside the United States.

Texas Severance Tax Rate Reduction. Natural gas production from qualifying Texas natural gas wells spudded or completed after August 31, 1996 is entitled to a reduced severance tax rate for the first 120 consecutive months of production. However, the cumulative value of the tax reduction cannot exceed 50 percent of the drilling and completion costs incurred on a well-by-well basis.

Executive Officers of the Registrant

The current executive officers of EOG and their names and ages (as of February 25, 2016) are as follows:

Name	Age	Position
William R. Thomas	63	Chairman of the Board and Chief Executive Officer
Gary L. Thomas	66	President and Chief Operating Officer
Lloyd W. Helms, Jr.	58	Executive Vice President, Exploration and Production
David W. Trice	45	Executive Vice President, Exploration and Production
Timothy K. Driggers	54	Vice President and Chief Financial Officer
Michael P. Donaldson	53	Vice President, General Counsel and Corporate Secretary

William R. Thomas was elected Chairman of the Board and Chief Executive Officer effective January 2014. He was elected Senior Vice President and General Manager of EOG's Fort Worth, Texas, office in June 2004, Executive Vice President and General Manager of EOG's Fort Worth, Texas, office in February 2007 and Senior Executive Vice President, Exploitation in February 2011. He subsequently served as Senior Executive Vice President, Exploration from July 2011 to September 2011, as President from September 2011 to July 2013 and as President and Chief Executive Officer from July 2013 to December 2013. Mr. Thomas joined a predecessor of EOG in January 1979. Mr. Thomas is EOG's principal executive officer.

Gary L. Thomas was elected Chief Operating Officer in September 2011 and President in March 2015. He was elected Executive Vice President, North America Operations in May 1998, Executive Vice President, Operations in May 2002, and served as Senior Executive Vice President, Operations from February 2007 to September 2011. He also previously served as Senior Vice President and General Manager of EOG's Midland, Texas, office. Mr. Thomas joined a predecessor of EOG in July 1978.

Lloyd W. Helms, Jr. was elected Executive Vice President, Exploration and Production in August 2013. He was elected Vice President, Engineering and Acquisitions in September 2006, Vice President and General Manager of EOG's Calgary, Alberta, Canada office in March 2008, and served as Executive Vice President, Operations from February 2012 to August 2013. Mr. Helms joined a predecessor of EOG in February 1981.

David W. Trice was elected Executive Vice President, Exploration and Production in August 2013. He served as Vice President and General Manager of EOG's Fort Worth, Texas, office from May 2010 to August 2013. Prior to that, he served in various geological and management positions at EOG. Mr. Trice joined EOG in November 1999.

Timothy K. Driggers was elected Vice President and Chief Financial Officer in July 2007. He was elected Vice President and Controller of EOG in October 1999, was subsequently named Vice President, Accounting and Land Administration in October 2000 and Vice President and Chief Accounting Officer in August 2003. Mr. Driggers is EOG's principal financial officer. Mr. Driggers joined a predecessor of EOG in August 1995.

Michael P. Donaldson was elected Vice President, General Counsel and Corporate Secretary in May 2012. He was elected Corporate Secretary in May 2008, and was appointed Deputy General Counsel and Corporate Secretary in July 2010. Mr. Donaldson joined EOG in September 2007.

ITEM 1A. *Risk Factors*

Our business and operations are subject to many risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition, results of operations or cash flows could be materially and adversely affected and the trading price of our common stock could decline. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes. Unless the context requires otherwise, "we," "us," "our" and "EOG" refer to EOG Resources, Inc. and its subsidiaries.

Crude oil, natural gas and NGL prices are volatile, and the substantial and extended decline in commodity prices has had, and may continue to have, a material and adverse effect on us and the trading price of our common stock.

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

- the level of consumer demand;
- domestic and worldwide supplies of crude oil, NGLs and natural gas;
- the price and quantity of imported and exported crude oil, NGLs and natural gas;
- domestic and international drilling activity;
- the actions of other crude oil exporting nations, including the Organization of Petroleum Exporting Countries;
- weather conditions and changes in weather patterns;
- the availability, proximity and capacity of appropriate transportation facilities, gathering, processing and compression facilities and refining facilities;
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation, including environmental regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others; and
- the effect of worldwide energy conservation measures.

Beginning in the fourth quarter of 2014 and continuing through 2015 and into 2016, crude oil prices have substantially declined. In addition, natural gas and NGL prices began to decline substantially in the second quarter of 2014, and such declines continued during 2015 and into 2016. The above-described factors and the volatility of commodity prices make it difficult to predict future crude oil, natural gas and NGL prices. As a result, we cannot predict how long these lower prices will continue, and there can be no assurance that the prices for crude oil, natural gas and/or NGLs will not decline further.

Our cash flows and results of operations depend to a great extent on prevailing commodity prices. Accordingly, the recent substantial and extended decline in commodity prices can materially and adversely affect the amount of cash flows we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

Lower commodity prices can also reduce the amount of crude oil, natural gas and NGLs that we can produce economically. Substantial declines in the prices of these commodities can also render uneconomic a significant portion of our exploration, development and exploitation projects, resulting in our having to make significant downward adjustments to our estimated proved reserves. As a result, prolonged or substantial declines in commodity prices can materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance our capital expenditures and, in turn, the trading price of our common stock.

In addition, significant prolonged decreases in commodity prices may cause the expected future cash flows from our properties to fall below their respective net book values, which will require us to write down the value of our properties. Such asset impairments could materially and adversely affect our results of operations and financial position.

In fact, the substantial declines in crude oil, natural gas and NGL prices that began in 2014 and which have continued into 2016 have materially and adversely affected the amount of cash flows we have available for our capital expenditures and other operating expenses, our results of operations during fiscal year 2015 and the trading price of our common stock.

As a result of the decreased cash flow available for capital expenditures, we have delayed our drilling and completion plans with respect to certain of our properties. These delays may result in impacts to our production volumes as well as cause us to potentially shut-in certain wells and incur associated lease payment obligations. Such commodity price declines also resulted in an impairment charge (i.e., "write-down") of $6.3 billion in 2015 with respect to our proved oil and gas properties and related assets. Such declines in commodity prices also resulted in our making a downward adjustment of 574 million barrels of oil equivalent to our estimated net proved reserves at December 31, 2015.

In addition, our 2016 financial condition, cash flows and results of operations will be adversely affected if commodity prices remain at current levels or decline further. If commodity prices remain at current levels for an extended period of time or continue to decline, we may be limited in our ability to maintain our current level of dividends on our common stock. Further, if commodity prices remain at current levels or decline further, we may be required to incur additional impairment charges and/or make significant additional downward adjustments to our proved reserve estimates. As a result, our financial condition and results of operations will be further adversely affected.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). As a result, we may not recover all or any portion of our investment in new wells.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental, health and safety laws and regulations relating to air emissions, hydraulic fracturing, access to and use of water, disposal of produced water, drilling fluids and other wastes, laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas, and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required federal, state, tribal and other permits and licenses, which may be affected by (among other things) government shutdowns or other suspensions of, or delays in, government services;
- the availability of, costs associated with and terms of contractual arrangements for properties, including mineral licenses and leases, pipelines, rail cars, crude oil hauling trucks and qualified drivers and facilities and equipment to gather, process, compress, transport and market crude oil, natural gas and related commodities; and
- the costs of, or shortages or delays in the availability of, drilling rigs, hydraulic fracturing services, pressure pumping equipment and supplies, tubular materials, water, sand, disposal facilities, qualified personnel and other necessary facilities, equipment, materials, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

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

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

- well blowouts and cratering;
- loss of well control;
- crude oil spills, natural gas leaks and pipeline ruptures;
- pipe failures and casing collapses;
- uncontrollable flows of crude oil, natural gas, formation water or drilling fluids;
- releases of chemicals, wastes or pollutants;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and other natural disasters;
- fires and explosions;
- terrorism, vandalism and physical, electronic and cyber security breaches;
- formations with abnormal or unexpected pressures;
- leaks or spills in connection with, or associated with, the gathering, processing, compression and transportation of crude oil and natural gas; and
- malfunctions of, or damage to, gathering, processing, compression and transportation facilities and equipment and other facilities and equipment utilized in support of our crude oil and natural gas operations.

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

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

We maintain insurance against many, but not all, such losses and liabilities in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. The occurrence of any of these events and any losses or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage, would reduce the funds available to us for our operations and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Our ability to sell and deliver our crude oil and natural gas production could be materially and adversely affected if adequate gathering, processing, compression and transportation facilities and equipment are unavailable.

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities and equipment owned by third parties. These facilities may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. In particular, in certain newer plays, the capacity of gathering, processing, compression and transportation facilities and equipment may not be sufficient to accommodate potential production from existing and new wells. In addition, lack of financing, construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new gathering, processing, compression and transportation facilities and equipment by third parties or us, and we may experience delays or increased costs in accessing the pipelines, gathering systems or rail systems necessary to transport our production to points of sale or delivery.

Any significant change in market or other conditions affecting gathering, processing, compression or transportation facilities and equipment or the availability of these facilities, including due to our failure or inability to obtain access to these facilities and equipment on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

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

The rate of production from crude oil and natural gas properties generally declines as reserves are produced. Except to the extent that we conduct successful exploration, exploitation and development activities, acquire additional properties containing reserves or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our reserves will decline as they are produced. Maintaining our production of crude oil and natural gas at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves. To the extent we are unsuccessful in acquiring or finding additional reserves, our future cash flows and results of operations and, in turn, the trading price of our common stock could be materially and adversely affected.

We incur certain costs to comply with government regulations, particularly regulations relating to environmental protection and safety, and could incur even greater costs in the future.

Our crude oil and natural gas operations and supporting activities are regulated extensively by federal, state, tribal and local governments and regulatory agencies, both domestically and in the foreign countries in which we do business, and are subject to interruption or termination by governmental and regulatory authorities based on environmental, health, safety or other considerations. Moreover, we have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, health, safety and other regulations. Further, the regulatory environment could change in ways that we cannot predict and that might substantially increase our costs of compliance and, in turn, materially and adversely affect our business, results of operations and financial condition.

Specifically, as a current or past owner or lessee and operator of crude oil and natural gas properties, we are subject to various federal, state, tribal, local and foreign regulations relating to the discharge of materials into, and the protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution cleanup resulting from current or past operations, subject us to liability for pollution damages and require suspension or cessation of operations in affected areas. Moreover, we are subject to the United States (U.S.) Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions. Changes in, or additions to, these regulations could lead to increased operating and compliance costs and, in turn, materially and adversely affect our business, results of operations and financial condition.

Local, state, national and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. For example, the U.S. EPA recently proposed regulations that would require operators to reduce methane emissions and emissions of volatile organic compounds from crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement and subsequent domestic and international regulations will have adverse effects on the market for crude oil, natural gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, crude oil, natural gas and other fossil fuel products. EOG is unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. In March 2015, however, the U.S. Bureau of Land Management issued new regulations applicable to hydraulic fracturing activities on federal and Indian lands, including requirements for chemical disclosure, wellbore integrity, and handling of flow back and produced water. In addition, there have been various other proposals to regulate hydraulic fracturing at the federal level. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements, additional operating and compliance costs and additional operating restrictions. Moreover, some state and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations. Any such federal or state requirements, restrictions or conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. Accordingly, our production of crude oil and natural gas could be materially and adversely affected. For additional discussion regarding climate change regulation and hydraulic fracturing regulation, see Climate Change - United States and Hydraulic Fracturing - United States under ITEM 1, Business - Regulation.

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

Certain U.S. federal income tax deductions currently available with respect to crude oil and natural gas exploration and production may cease to be available in the future or may be otherwise modified as a result of future legislation.

Legislation may be proposed in the future that could, if enacted into law, make significant changes to U.S. tax laws. Such changes may include, but not be limited to, the elimination of certain U.S. federal income tax incentives currently available to crude oil and natural gas exploration and production companies, such as with respect to the intangible drilling costs deduction and bonus tax depreciation. We can give no assurance whether such changes or similar or other tax law changes will be proposed and, if enacted, how soon any such changes would become effective. The enactment of any such changes in U.S. federal income tax laws could materially and adversely affect our cash flows, results of operations and financial condition.

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

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, the unavailability of gathering, processing, compression, transportation or refining facilities or equipment or field labor issues, or intentionally as a result of market conditions such as crude oil or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted or shut in, our cash flows and, in turn, our financial condition and results of operations could be materially and adversely affected.

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

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems (such as title or environmental issues), nor may they permit us to become sufficiently familiar with the properties in order to assess fully their deficiencies and potential. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. In addition, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further below), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

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

We make, and will continue to make, substantial capital expenditures for the acquisition, exploration, development, production and transportation of crude oil and natural gas reserves. We intend to finance our capital expenditures primarily through our cash flows from operations, commercial paper borrowings, sales of non-core assets and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facility and public and private equity and debt offerings.

Lower crude oil and natural gas prices, however, reduce our cash flows. The lower commodity price environment could also delay or impair our ability to consummate certain planned non-core asset sales and divestitures. Further, if the condition of the credit and capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable, if at all. Weakness and/or volatility in domestic and global financial markets or economic conditions and a depressed commodity price environment may increase the interest rates that lenders and commercial paper investors require us to pay and adversely affect our ability to finance our capital expenditures through equity or debt offerings or other borrowings. A reduction in our cash flows (for example, as a result of continued lower crude oil and natural gas prices or unanticipated well shut-ins) and the corresponding adverse effect on our financial condition and results of operations may also increase the interest rates that lenders and commercial paper investors require us to pay. In addition, a substantial increase in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations.

Our ability to obtain financings and the terms of any financings are, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. Factors that may impact our credit ratings include our debt levels; planned asset purchases or sales; near-term and long-term production growth opportunities; liquidity; asset quality; cost structure; product mix; and commodity pricing levels (including, but not limited to, the estimates and assumptions of credit rating agencies with respect to future commodity prices). In February 2016, Standard & Poor's Ratings Services (an independent credit rating agency), as a result of its lowered assumptions with respect to future commodity prices, lowered its credit ratings of several investment grade-rated U.S. oil and gas exploration and production companies, including its rating of our long-term debt. We expect Moody's Investors Service, Inc. (also an independent credit rating agency) will take similar action in the near future with respect to its ratings of our debt and its ratings of the debt of other U.S. oil and gas exploration and production companies. Such ratings downgrades could increase our borrowing costs and may adversely impact our ability to access financings. In addition, we cannot provide any assurance that our credit ratings will remain in effect for any given period of time or that our credit ratings will be raised in the future, nor can we provide any assurance that any of our credit ratings will not be further lowered.

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

We have various customers for the crude oil, natural gas and related commodities that we produce as well as various other contractual counterparties, including several financial institutions and affiliates of financial institutions. Domestic and global economic conditions, including the financial condition of financial institutions generally, while weakened in recent years, have improved somewhat. However, there continues to be weakness and volatility in domestic and global financial markets and a depressed commodity price environment, and there is the possibility that lenders may react by tightening credit. These conditions and factors may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes.

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

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

Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) necessary to explore for, develop, produce, market and transport crude oil and natural gas. In addition, many of our competitors have financial and other resources substantially greater than those we possess and have established strategic long-term positions and strong governmental relationships in countries in which we may seek new or expanded entry. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

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

Estimating quantities of crude oil, NGL and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management and our independent petroleum consultants. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Also, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

To prepare estimates of our economically recoverable crude oil, NGL and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, gathering, processing, compression and transportation costs, severance, ad valorem and other applicable taxes, capital expenditures and workover and remedial costs, many of which factors are or may be beyond our control. Our actual reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance, including any significant revisions or "write-downs" to our existing reserve estimates, could materially and adversely affect our business, financial condition and results of operations and, in turn, the trading price of our common stock. For related discussion, see ITEM 2, Properties - Oil and Gas Exploration and Production - Properties and Reserves and Supplemental Information to Consolidated Financial Statements.

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

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

In addition, our exploration, exploitation and development activities and equipment can be adversely affected by extreme weather conditions, such as winter storms, flooding and hurricanes in the Gulf of Mexico, which may cause a loss of production from temporary cessation of activity or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs, the installation and operation of gathering, processing, compression and transportation facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. Such extreme weather conditions and changes in weather patterns may materially and adversely affect our business and, in turn, our financial condition and results of operations.

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

We use derivative instruments (primarily financial price swap, option, swaption, collar and basis swap contracts) to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flows. To the extent that we engage in hedging activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of increases in crude oil and natural gas prices above the prices established by our hedging contracts. Our forecasted natural gas production for 2016 is currently approximately 4% hedged at approximately $2.49 per million British thermal units, and none of our forecasted crude oil production for 2016 is currently hedged. As a result, a significant portion of our forecasted production for 2016 remains unhedged and subject to fluctuating market prices. If we are ultimately unable to hedge additional production volumes for 2016 and beyond, we will be impacted by further commodity price declines, which may result in lower net cash provided by operating activities. In addition, our hedging activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

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

As discussed in the risk factor immediately above, we use derivative instruments to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flows. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which, among other matters, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (CFTC), the Securities and Exchange Commission (SEC) and certain federal agencies that regulate the banking and insurance sectors (the Prudential Regulators) adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act are yet to be adopted, the CFTC, the SEC and the Prudential Regulators have issued numerous rules, including a rule establishing an "end-user" exception to mandatory clearing (End-User Exception), a rule regarding margin for uncleared swaps (Margin Rule) and a proposed rule imposing position limits (Position Limits Rule).

We qualify as a "non-financial entity" for purposes of the End-User Exception and, as such, we are eligible for, and expect to utilize, such exception. As a result, our hedging activities will not be subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. We also qualify as a "non-financial entity" for purposes of the Margin Rule; therefore, our uncleared swaps are not subject to regulatory margin requirements. Finally, we believe our hedging activities would constitute bona fide hedging under the Position Limits Rule and would not be subject to limitation under such rule if it is enacted. However, many of our hedge counterparties and many other market participants may not be eligible for the End-User Exception, may be subject to mandatory clearing or the Margin Rule for swaps with some or all of their other swap counterparties, and/or may be subject to the Position Limits Rule. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations related to derivatives (collectively, Foreign Regulations) which may apply to our transactions with counterparties subject to such Foreign Regulations.

The Dodd-Frank Act, the rules adopted thereunder and the Foreign Regulations could increase the cost of derivative contracts, alter the terms of derivative contracts, reduce the availability of derivatives to protect against the price risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If our use of derivatives is reduced as a result of the Dodd-Frank Act, related regulations or the Foreign Regulations, our results of operations may become more volatile, and our cash flows may be less predictable, which could adversely affect our ability to plan for, and fund, our capital expenditure requirements. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

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

Our business and prospects for future success, including the successful implementation of our strategies and handling of issues integral to our future success, depend to a significant extent upon the continued service and performance of our management team. The loss of any member of our management team, and our inability to attract, motivate and retain substitute management personnel with comparable experience and skills, could materially and adversely affect our business, financial condition and results of operations.

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

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

- increases in taxes and governmental royalties;
- changes in laws and policies governing operations of foreign-based companies;
- loss of revenue, loss of or damage to equipment, property and other assets and interruption of operations as a result of expropriation, nationalization, acts of terrorism, war, civil unrest and other political risks;
- unilateral or forced renegotiation, modification or nullification of existing contracts with governmental entities;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- currency restrictions and exchange rate fluctuations.

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

Unfavorable currency exchange rate fluctuations could adversely affect our results of operations.

The reporting currency for our financial statements is the U.S. dollar. However, certain of our subsidiaries are located in countries other than the U.S. and have functional currencies other than the U.S. dollar. The assets, liabilities, revenues and expenses of certain of these foreign subsidiaries are denominated in currencies other than the U.S. dollar. To prepare our consolidated financial statements, we must translate those assets, liabilities, revenues and expenses into U.S. dollars at then-applicable exchange rates. Consequently, increases and decreases in the value of the U.S. dollar versus other currencies will affect the amount of these items in our consolidated financial statements, even if the amount has not changed in the original currency. These translations could result in changes to our results of operations from period to period. For the fiscal year ended December 31, 2015, less than 1% of our net operating revenues related to operations of our foreign subsidiaries whose functional currency was not the U.S. dollar.

Our business could be adversely affected by security threats, including cybersecurity threats.

As a producer of crude oil and natural gas, we face various security threats, including cybersecurity threats to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, refineries, rail facilities and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition and results of operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruptions, or other disruptions to our operations.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position and results of operations.

Terrorist activities and military and other actions could materially and adversely affect us.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. The U.S. government has at times issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. Any such actions and the threat of such actions could materially and adversely affect us in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in crude oil and natural gas prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

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

Not applicable.

ITEM 2. ***Properties***

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates and discussions of EOG's net proved reserves of crude oil and condensate, natural gas liquids (NGLs) and natural gas, the qualifications of the preparers of EOG's reserve estimates, EOG's independent petroleum consultants and EOG's processes and controls with respect to its reserve estimates, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in "Supplemental Information to Consolidated Financial Statements" represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates by different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

In general, the rate of production from crude oil and natural gas properties declines as reserves are produced. Except to the extent EOG acquires additional properties containing proved reserves, conducts successful exploration, exploitation and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, the proved reserves of EOG will decline as reserves are produced. The volumes to be generated from future activities of EOG are therefore highly dependent upon the level of success in finding or acquiring additional reserves. For related discussion, see ITEM 1A, Risk Factors. EOG's estimates of reserves filed with other federal agencies are consistent with the information set forth in "Supplemental Information to Consolidated Financial Statements."

Acreage. The following table summarizes EOG's developed and undeveloped acreage at December 31, 2015. Excluded is acreage in which EOG's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2,168,651	1,700,323	2,895,940	2,006,080	5,064,591	3,706,403
Trinidad	75,667	65,669	50,338	39,725	126,005	105,394
United Kingdom	8,797	2,570	13,443	6,713	22,240	9,283
China	130,548	130,548	—	—	130,548	130,548
Canada	54,219	46,021	200,618	161,334	254,837	207,355
Argentina	—	—	183,916	79,451	183,916	79,451
Total	2,437,882	1,945,131	3,344,255	2,293,303	5,782,137	4,238,434

Most of our undeveloped oil and gas leases, particularly in the United States, are subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. Approximately 0.4 million net acres will expire in 2016, 0.3 million net acres will expire in 2017 and 0.1 million net acres will expire in 2018 if production is not established or we take no other action to extend the terms of the leases or obtain concessions. In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Producing Well Summary. EOG operated 10,074 gross and 8,751 net producing crude oil and natural gas wells at December 31, 2015. Gross crude oil and natural gas wells include 200 wells with multiple completions. The following table represents wells in which EOG owns a working interest, including non-EOG operated wells.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	4,842	3,846	6,024	5,261	10,866	9,107
Trinidad	13	10	34	29	47	39
China	—	—	31	31	31	31
Canada	10	1	24	23	34	24
Argentina	3	1	—	—	3	1
Total	4,868	3,858	6,113	5,344	10,981	9,202

Drilling and Acquisition Activities. During the years ended December 31, 2015, 2014 and 2013, EOG expended $4.9 billion, $7.9 billion and $7.0 billion, respectively, for exploratory and development drilling, facilities and acquisition of leases and producing properties, including asset retirement obligations of $53 million, $196 million and $134 million, respectively. The following tables set forth the results of the gross crude oil and natural gas wells completed for the years ended December 31, 2015, 2014 and 2013:

	Gross Development Wells Completed				Gross Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2015								
United States	494	16	9	519	2	—	—	2
Trinidad	—	3	—	3	—	1	—	1
China	—	—	—	—	—	3	2	5
Total	494	19	9	522	2	4	2	8
2014								
United States	901	47	8	956	12	—	5	17
Trinidad	—	1	—	1	—	—	—	—
United Kingdom	—	—	—	—	—	—	1	1
China	—	—	—	—	—	2	—	2
Canada	42	—	—	42	—	—	—	—
Argentina	—	—	—	—	—	—	3	3
Total	943	48	8	999	12	2	9	23
2013								
United States	909	57	22	988	7	2	3	12
Trinidad	—	1	—	1	—	1	—	1
United Kingdom	3	—	—	3	—	—	1	1
China	—	—	—	—	—	1	—	1
Canada	85	—	—	85	1	—	—	1
Argentina	—	—	—	—	1	—	—	1
Total	997	58	22	1,077	9	4	4	17

The following tables set forth the results of the net crude oil and natural gas wells completed for the years ended December 31, 2015, 2014 and 2013:

	Net Development Wells Completed				Net Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2015								
United States	457	14	8	479	2	—	—	2
Trinidad	—	2	—	2	—	1	—	1
China	—	—	—	—	—	3	2	5
Total	457	16	8	481	2	4	2	8
2014								
United States	807	39	7	853	11	—	5	16
Trinidad	—	1	—	1	—	—	—	—
United Kingdom	—	—	—	—	—	—	1	1
China	—	—	—	—	—	2	—	2
Canada	35	—	—	35	—	—	—	—
Argentina	—	—	—	—	—	—	1	1
Total	842	40	7	889	11	2	7	20
2013								
United States	788	50	15	853	6	2	3	11
Trinidad	—	1	—	1	—	1	—	1
United Kingdom	3	—	—	3	—	—	1	1
China	—	—	—	—	—	1	—	1
Canada	76	—	—	76	1	—	—	1
Argentina	—	—	—	—	1	—	—	1
Total	867	51	15	933	8	4	4	16

EOG participated in the drilling of wells that were in the process of being drilled or completed at the end of the period as set out in the table below for the years ended December 31, 2015, 2014 and 2013:

	Wells in Progress at End of Period					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
United States	516	429	388	327	320	280
Trinidad	—	—	1	1	—	—
China	—	—	2	2	2	2
Canada	—	—	—	—	13	8
Argentina	—	—	—	—	1	1
Total	516	429	391	330	336	291

EOG acquired wells, which includes the acquisition of additional interests in certain wells in which EOG previously owned an interest, as set out in the tables below for the years ended December 31, 2015, 2014 and 2013:

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2015						
United States	24	—	24	23	—	23
Total	24	—	24	23	—	23
2014						
United States	91	10	101	41	9	50
Total	91	10	101	41	9	50
2013						
United States	68	27	95	50	21	71
Total	68	27	95	50	21	71

All of EOG's drilling and completion activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. EOG's other property, plant and equipment primarily includes gathering, transportation and processing infrastructure assets, crude-by-rail assets, and sand mine and sand processing assets which support EOG's exploration and production activities. EOG does not own drilling rigs, hydraulic fracturing equipment or rail cars.

ITEM 3. ***Legal Proceedings***

The information required by this Item is set forth under the "Contingencies" caption in Note 8 of the Notes to Consolidated Financial Statements and is incorporated by reference herein.

ITEM 4. ***Mine Safety Disclosures***

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

PART II

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

EOG's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "EOG." The following table sets forth, for the periods indicated, the high and low sales price per share for EOG's common stock, as reported by the NYSE, and the amount of the cash dividend declared per share. The quarterly cash dividend on EOG's common stock has historically been declared in the quarter immediately preceding the quarter of payment and paid on January 31, April 30, July 31 and October 31 of each year (or, if such day is not a business day, the immediately preceding business day).

	Price Range		
	High	Low	Dividend Declared
2015			
First Quarter	$ 97.88	$ 82.72	$ 0.1675
Second Quarter	101.36	86.15	0.1675
Third Quarter	87.85	68.15	0.1675
Fourth Quarter	89.52	69.30	0.1675
2014			
First Quarter	$ 99.75	$ 80.63	$ 0.1250
Second Quarter	118.89	96.01	0.1250
Third Quarter	118.81	97.45	0.1675
Fourth Quarter	103.04	81.07	0.1675

As of February 3, 2016, there were approximately 2,100 record holders and approximately 339,000 beneficial owners of EOG's common stock.

EOG currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock in the future. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other factors, the financial condition, cash flow, level of exploration and development expenditure opportunities and future business prospects of EOG.

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs (2)
October 1, 2015 - October 31, 2015	24,430	$ 83.69	—	6,386,200
November 1, 2015 - November 30, 2015	15,850	$ 85.14	—	6,386,200
December 1, 2015 - December 31, 2015	25,847	$ 75.06	—	6,386,200
Total	66,127	$ 80.66		

(1) The 66,127 total shares for the quarter ended December 31, 2015, and the 580,815 total shares for the full year 2015, consist solely of shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share repurchase authorization of EOG's Board discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2015, EOG did not repurchase any shares under the Board-authorized repurchase program.

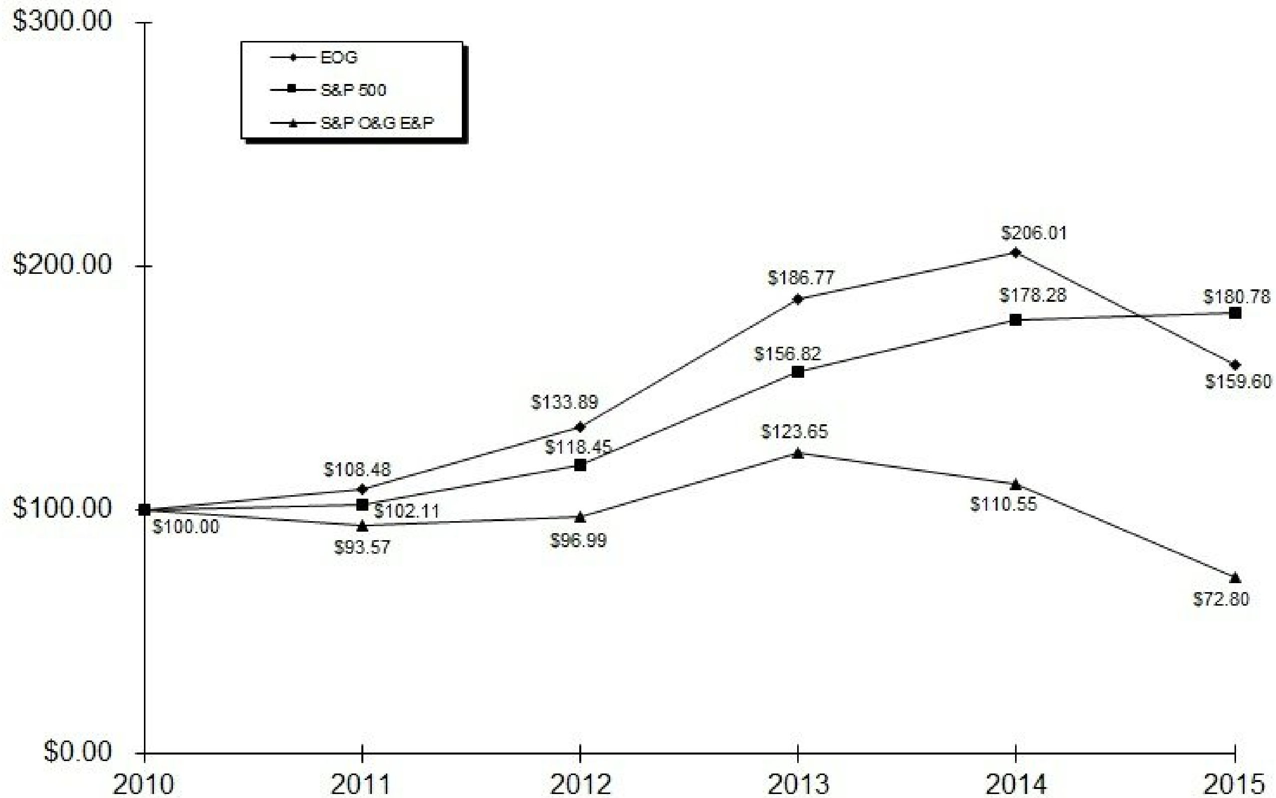
Comparative Stock Performance

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically requests that such information be treated as "soliciting material" or specifically incorporates such information by reference into such a filing.

The performance graph shown below compares the cumulative five-year total return to stockholders on EOG's common stock as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index (S&P 500) and the Standard and Poor's 500 Oil & Gas Exploration & Production Index (S&P O&G E&P). The comparison was prepared based upon the following assumptions:

1. $100 was invested on December 31, 2010 in each of the following: common stock of EOG, the S&P 500 and the S&P O&G E&P.
2. Dividends are reinvested.

Comparison of Five-Year Cumulative Total Returns
EOG, S&P 500 and S&P O&G E&P
(Performance Results Through December 31, 2015)



	2010		2011		2012		2013		2014		2015	
EOG	$	100.00	$	108.48	$	133.89	$	186.77	$	206.01	$	159.60
S&P 500	$	100.00	$	102.11	$	118.45	$	156.82	$	178.28	$	180.78
S&P O&G E&P	$	100.00	$	93.57	$	96.99	$	123.65	$	110.55	$	72.80

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

The following selected consolidated financial information should be read in conjunction with ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and ITEM 8, Financial Statements and Supplementary Data.

Year Ended December 31	**2015**	**2014**	**2013**	**2012**	**2011**
Statement of Income Data:					
Net Operating Revenues	$ 8,757,428	$ 18,035,340	$ 14,487,118	$ 11,682,636	$ 10,126,115
Operating Income (Loss)	$ (6,686,079)	$ 5,241,823	$ 3,675,211	$ 1,479,797	$ 2,113,309
Net Income (Loss)	$ (4,524,515)	$ 2,915,487	$ 2,197,109	$ 570,279	$ 1,091,123
Net Income (Loss) Per Share					
Basic	$ (8.29)	$ 5.36	$ 4.07	$ 1.07	$ 2.08
Diluted	$ (8.29)	$ 5.32	$ 4.02	$ 1.05	$ 2.05
Dividends Per Common Share	$ 0.670	$ 0.585	$ 0.375	$ 0.340	$ 0.320
Average Number of Common Shares					
Basic	545,697	543,443	540,341	535,155	525,470
Diluted	545,697	548,539	546,227	541,524	532,536

At December 31	**2015**	**2014**	**2013**	**2012**	**2011**
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 24,210,721	$ 29,172,644	$ 26,148,836	$ 23,337,681	$ 21,288,824
Total Assets	26,975,244	34,762,687	30,574,238	27,336,578	24,838,797
Total Debt	6,660,264	5,909,933	5,913,221	6,312,181	5,009,166
Total Stockholders' Equity	12,943,035	17,712,582	15,418,459	13,284,764	12,640,904

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) crude oil and natural gas companies in the United States with proved reserves in the United States, Trinidad, the United Kingdom and China. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG's strategy.

EOG realized a net loss of $4,525 million during 2015 as compared to net income of $2,915 million for 2014. During 2015, impairments of proved oil and gas properties and other assets totaling $6,326 million, $4,141 million net of tax, were recognized primarily due to the decline in commodity prices. At December 31, 2015, EOG's total estimated net proved reserves were 2,118 million barrels of oil equivalent (MMBoe), a decrease of 379 MMBoe from December 31, 2014. During 2015, net proved crude oil and condensate and natural gas liquids (NGLs) reserves decreased by 126 million barrels (MMBbl), and net proved natural gas reserves decreased by 1,517 billion cubic feet or 253 MMBoe.

Operations

Several important developments have occurred since January 1, 2015.

United States. EOG's efforts to identify plays with large reserve potential have proven to be successful. EOG continues to drill numerous wells in large acreage plays, which in the aggregate have contributed substantially to, and are expected to continue to contribute substantially to, EOG's crude oil and liquids-rich natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise to unconventional crude oil and liquids-rich reservoirs. During 2015, EOG focused on increasing drilling and completion efficiencies, testing methods to improve the recovery factor of oil-in-place and reducing operating costs through efficiency improvements and service cost reductions. These efficiency gains along with realized lower service costs resulted in lower drilling and completion costs and decreased operating expenses. EOG continues to evaluate certain potential crude oil and liquids-rich natural gas exploration and development prospects. On a volumetric basis, as calculated using the ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas, crude oil and condensate and NGL production accounted for approximately 71% of United States production during 2015, consistent with 2014. During 2015, drilling occurred primarily in the Eagle Ford, Delaware Basin and North Dakota Bakken plays, where EOG has built an inventory of uncompleted wells. In addition, EOG continues to look for opportunities to add drilling inventory through leasehold acquisitions, farm-ins or tactical acquisitions and to evaluate certain potential crude oil and liquids-rich natural gas exploration and development prospects. In 2015, EOG completed four transactions to acquire certain proved crude oil properties and related assets in the Delaware Basin. The aggregate purchase price of the transactions totaled approximately $400 million. EOG's major producing areas in the United States are in New Mexico, North Dakota, Texas, Utah and Wyoming.

During 2015, due to the decline in commodity prices, proved oil and gas properties and related assets in the United States were written down to their fair value resulting in pretax impairment charges of $6,130 million, $3,945 million net of tax. Impairments were related to legacy natural gas assets and marginal liquids plays.

Trinidad. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium (SECC) Block, Modified U(a) Block, Block 4(a) and Modified U(b) Block and the Sercan Area (formerly known as the EMZ area) have been developed and are producing natural gas which is sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary and crude oil and condensate which is sold to the Petroleum Company of Trinidad and Tobago Limited. EOG completed three net wells in 2015, finishing its SECC Block and Modified U(b) Block drilling program that was initiated in 2014. In 2016, EOG expects to complete one net well and install infrastructure in the Sercan Area.

Other International. As previously reported, during the fourth quarter of 2014, EOG completed the divestiture of substantially all its assets in Canada (see Note 17 to the Consolidated Financial Statements). At the time of the sales, production from the divested assets totaled approximately 7,050 barrels of crude oil per day, 580 barrels of NGLs per day and 43.5 million cubic feet of natural gas per day. Information related to EOG's remaining Canadian operations is presented in the "Other International" segment.

In the United Kingdom, EOG continues to make progress in the development of its 100% working interest East Irish Sea Conwy crude oil discovery. Modifications to the nearby third-party owned Douglas platform, which will be used to process Conwy production, began in 2013 and continued throughout 2014 and 2015. First production from the Conwy field is anticipated in March 2016. During 2015, EOG recognized a pretax impairment charge of $186 million for the Conwy project as a result of crude oil price declines.

In 2015, EOG drilled four wells and completed three wells, one of which was drilled in 2014, in the Sichuan Basin, Sichuan Province, China. The successful completions extended the Shaximiao development in the Chuan Zhong Block and provides additional opportunities in the future.

EOG's activity in Argentina is focused on the Vaca Muerta oil shale formation in the Neuquén Province. Management is currently evaluating options for its investment.

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

Capital Structure

One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 34% at December 31, 2015 and 25% at December 31, 2014. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity. At December 31, 2015, $400 million aggregate principal amount of its 2.500% Senior Notes due 2016 (the 2016 Notes) and $260 million principal amount of commercial paper borrowings were reclassified as long-term debt based upon EOG's intent and ability to ultimately replace such amount with other long-term debt.

On January 14, 2016, EOG closed its sale of $750 million aggregate principal amount of its 4.15% Senior Notes due 2026 and $250 million aggregate principal amount of its 5.10% Senior Notes due 2036 (collectively, the New Notes). Interest on the New Notes is payable semi-annually in arrears on January 15 and July 15 of each year, beginning July 15, 2016. Proceeds from the issuance of the New Notes totaled approximately $991 million and were used to repay the $400 million aggregate principal amount of the 2016 Notes when such notes came due on February 1, 2016 and for general corporate purposes, including the repayment of outstanding commercial paper borrowings and funding of future capital expenditures.

On July 21, 2015, EOG entered into a new $2.0 billion senior unsecured Revolving Credit Agreement (2015 Agreement) with domestic and foreign lenders (Banks). The 2015 Agreement replaced EOG's $2.0 billion senior unsecured revolving credit agreement which was canceled by EOG upon the closing of the 2015 Agreement. The 2015 Agreement has a scheduled maturity date of July 21, 2020, and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods, subject to certain terms and conditions. The 2015 Agreement commits the Banks to provide advances up to an aggregate principal amount of $2.0 billion at any one time outstanding, with an option for EOG to request increases in the aggregate commitments to an amount not to exceed $3.0 billion, subject to certain terms and conditions.

On June 1, 2015, EOG repaid upon maturity the $500 million aggregate principal amount of its 2.95% Senior Notes due 2015.

On March 17, 2015, EOG closed its sale of $500 million aggregate principal amount of its 3.15% Senior Notes due 2025 and $500 million aggregate principal amount of its 3.90% Senior Notes due 2035 (together, the Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2015. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes.

During 2015, EOG funded $5.2 billion in exploration and development and other property, plant and equipment expenditures (excluding asset retirement obligations), repaid at maturity $500 million aggregate principal amount of long-term debt, paid $367 million in dividends to common stockholders and purchased $49 million of treasury stock in connection with stock compensation plans, primarily by utilizing net cash provided from its operating activities, net proceeds from the sale of the Notes, commercial paper borrowings, net proceeds of $193 million from the sale of assets and $26 million of excess tax benefits from stock compensation.

Total anticipated 2016 capital expenditures are estimated to range from approximately $2.4 billion to $2.6 billion, excluding acquisitions. The majority of 2016 expenditures will be focused on United States crude oil drilling activities. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under the 2015 Agreement and equity and debt offerings.

When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2015, should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning on page F-1.

Net Operating Revenues

During 2015, net operating revenues decreased $9,278 million, or 51%, to $8,757 million from $18,035 million in 2014. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, NGLs and natural gas, decreased $6,188 million, or 49%, to $6,404 million in 2015 from $12,592 million in 2014. Revenues from the sales of crude oil and condensate and NGLs in 2015 were approximately 83% of total wellhead revenues compared to 85% in 2014. During 2015, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million compared to net gains of $834 million in 2014. Gathering, processing and marketing revenues decreased $1,793 million during 2015, to $2,253 million from $4,046 million in 2014. Net losses on asset dispositions totaled $9 million in 2015 compared to net gains on asset dispositions of $508 million in 2014.

Wellhead volume and price statistics for the years ended December 31, 2015, 2014 and 2013 were as follows:

Year Ended December 31	**2015**	**2014**	**2013**
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	283.3	282.0	212.1
Trinidad	0.9	1.0	1.2
Other International (2)	0.2	5.9	7.1
Total	**284.4**	**288.9**	**220.4**
Average Crude Oil and Condensate Prices ($/Bbl) (3)			
United States	$ 47.55	$ 92.73	$ 103.81
Trinidad	39.51	84.63	90.30
Other International (2)	57.32	86.75	87.08
Composite	**47.53**	**92.58**	**103.20**
Natural Gas Liquids Volumes (MBbld) (1)			
United States	76.9	79.7	64.3
Other International (2)	0.1	0.6	0.9
Total	**77.0**	**80.3**	**65.2**
Average Natural Gas Liquids Prices ($/Bbl) (3)			
United States	$ 14.50	$ 31.84	$ 32.46
Other International (2)	4.61	40.73	39.45
Composite	**14.49**	**31.91**	**32.55**
Natural Gas Volumes (MMcfd) (1)			
United States	886	920	908
Trinidad	349	363	355
Other International (2)	30	70	84
Total	**1,265**	**1,353**	**1,347**
Average Natural Gas Prices ($/Mcf) (3)			
United States	$ 1.97	$ 3.93	$ 3.32
Trinidad	2.89	3.65	3.68
Other International (2)	5.05	4.40	3.39
Composite	**2.30**	**3.88**	**3.42**
Crude Oil Equivalent Volumes (MBoed) (4)			
United States	507.9	515.0	427.9
Trinidad	59.1	61.5	60.4
Other International (2)	5.2	18.2	21.8
Total	**572.2**	**594.7**	**510.1**
Total MMBoe (4)	**208.9**	**217.1**	**186.2**

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

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

(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, NGLs and natural gas. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs 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.

2015 compared to 2014. Wellhead crude oil and condensate revenues in 2015 decreased $4,807 million, or 49%, to $4,935 million from $9,742 million in 2014, due to a lower composite average wellhead crude oil and condensate price ($4,677 million) and a decrease of 5 MBbld, or 2%, in wellhead crude oil and condensate deliveries ($131 million). The decrease in deliveries primarily reflects decreased production in the North Dakota Bakken, the Fort Worth Barnett Shale area and Other International, partially offset by increased production in the Permian Basin and Eagle Ford. The decrease in Other International is due to the sale of the Canadian assets. EOG's composite wellhead crude oil and condensate price for 2015 decreased 49% to $47.53 per barrel compared to $92.58 per barrel in 2014.

NGL revenues in 2015 decreased $526 million, or 56%, to $408 million from $934 million in 2014, due to a lower composite average price ($490 million) and a decrease of 3 MBbld, or 4%, in NGL deliveries ($36 million). EOG's composite NGL price in 2015 decreased 55% to $14.49 per barrel compared to $31.91 per barrel in 2014.

Wellhead natural gas revenues in 2015 decreased $855 million, or 45%, to $1,061 million from $1,916 million in 2014, primarily due to a lower composite wellhead natural gas price ($730 million) and a decrease in wellhead natural gas deliveries ($125 million). EOG's composite average wellhead natural gas price decreased 41% to $2.30 per Mcf in 2015 compared to $3.88 per Mcf in 2014. Natural gas deliveries in 2015 decreased 7% to 1,265 MMcfd as compared to 1,353 MMcfd in 2014. The decrease in production was due to decreased production in Other International (40 MMcfd), the United States (34 MMcfd) and Trinidad (14 MMcfd). In the United States, decreased production was due primarily to lower production in the Upper Gulf Coast, Fort Worth Barnett Shale and South Texas areas, partially offset by increased production of associated gas in the Eagle Ford and Permian Basin. The decline in Other International primarily reflects the sale of the Canadian assets.

During 2015, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $730 million. During 2014, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $834 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $34 million.

Gathering, processing and marketing revenues are revenues generated from sales of third-party crude oil, NGLs, and natural gas as well as gathering fees associated with gathering third-party natural gas and revenues from sales of EOG-owned sand. Purchases and sales of third-party crude oil and natural gas are utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs of purchasing third-party crude oil and natural gas and the associated transportation costs as well as costs associated with EOG-owned sand sold to third parties.

Gathering, processing and marketing revenues less marketing costs in 2015 declined $53 million compared to 2014, primarily due to lower margins on crude oil and natural gas marketing activities and losses on sand sales.

2014 compared to 2013. Wellhead crude oil and condensate revenues in 2014 increased $1,441 million, or 17%, to $9,742 million from $8,301 million in 2013, due to an increase of 68.5 MBbld, or 31%, in wellhead crude oil and condensate deliveries ($2,558 million), partially offset by a lower composite average wellhead crude oil and condensate price ($1,117 million). The increase in deliveries primarily reflects increased production in the Eagle Ford, the North Dakota Bakken and the Permian Basin. EOG's composite wellhead crude oil and condensate price for 2014 decreased 10% to $92.58 per barrel compared to $103.20 per barrel in 2013.

NGL revenues in 2014 increased $160 million, or 21%, to $934 million from $774 million in 2013, due to an increase of 15 MBbld, or 23%, in NGL deliveries ($179 million), partially offset by a lower composite average price ($19 million). The increase in deliveries primarily reflects increased volumes in the Eagle Ford and the Permian Basin. EOG's composite NGL price in 2014 decreased 2% to $31.91 per barrel compared to $32.55 per barrel in 2013.

Wellhead natural gas revenues in 2014 increased $235 million, or 14%, to $1,916 million from $1,681 million in 2013, primarily due to a higher composite wellhead natural gas price. EOG's composite average wellhead natural gas price increased 13% to $3.88 per Mcf in 2014 compared to $3.42 per Mcf in 2013. Natural gas deliveries in 2014 increased less than 1% to 1,353 MMcfd as compared to 1,347 MMcfd in 2013. Increased production in the United States (12 MMcfd) and Trinidad (8 MMcfd) was offset by lower production in Canada (15 MMcfd). In the United States, increased production of associated natural gas in the Eagle Ford and Permian Basin areas was partially offset by lower production in the Upper Gulf Coast and Fort Worth Basin Barnett Shale areas.

During 2014, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $834 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $34 million. During 2013, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $166 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $116 million.

Gathering, processing and marketing revenues less marketing costs in 2014 declined $75 million compared to 2013, primarily due to lower margins on crude oil marketing activities.

Operating and Other Expenses

2015 compared to 2014. During 2015, operating expenses of $15,444 million were $2,650 million higher than the $12,794 million incurred during 2014. Operating expenses for 2015 included impairments of proved properties, other property, plant and equipment and other assets of $6,326 million primarily due to commodity price declines. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2015 and 2014:

	2015	2014
Lease and Well	$ 5.66	$ 6.53
Transportation Costs	4.07	4.48
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	15.27	17.90
Other Property, Plant and Equipment	0.59	0.53
General and Administrative (G&A)	1.75	1.85
Net Interest Expense	1.14	0.93
Total (1)	**$ 28.48**	**$ 32.22**

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2015 compared to 2014 are set forth below. See "Net Operating Revenues" above for a discussion of production volumes.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain crude oil and natural gas wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses of $1,182 million in 2015 decreased $234 million from $1,416 million in 2014 primarily due to lower operating and maintenance costs in the United States ($125 million), lower lease and well expenses in Other International ($99 million) primarily due to the sale of the Canadian assets and lower workover expenditures in the United States ($21 million), partially offset by increased lease and well administrative expenses in the United States ($12 million).

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include transportation fees, costs associated with crude-by-rail operations, the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees and fuel costs.

Transportation costs of $849 million in 2015 decreased $123 million from $972 million in 2014 primarily due to decreased transportation costs in the Rocky Mountain area ($81 million) and the Eagle Ford ($48 million) primarily due to an increase in the use of pipelines to transport crude oil production, partially offset by increased transportation costs related to higher production from the Permian Basin ($19 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual DD&A group calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells and reserve revisions (upward or downward) primarily related to well performance, economic factors and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from period to period. DD&A of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses in 2015 decreased $683 million to $3,314 million from $3,997 million in 2014. DD&A expenses associated with oil and gas properties in 2015 were $691 million lower than in 2014 primarily due to lower unit rates in the United States ($513 million) and Trinidad ($28 million), a decrease in production in the United States ($44 million) and lower DD&A expense in Other International ($104 million) primarily due to the sale of the Canadian assets. Unit rates in the United States decreased primarily due to impairments of proved oil and gas properties (see Note 14 to the Consolidated Financial Statements), upward reserve revisions and reserves added at lower costs as a result of increased efficiencies.

G&A expenses of $367 million in 2015 were $35 million lower than 2014 primarily due to lower employee-related expenses.

Net interest expense of $237 million in 2015 was $36 million higher than 2014 primarily due to interest incurred on the Notes issued in March 2015 ($28 million), as well as a decrease in capitalized interest ($15 million). This was partially offset by the reduction of interest on debt repaid in June 2015 and during 2014 ($11 million).

Exploration costs of $149 million in 2015 decreased $35 million from $184 million in 2014 primarily due to decreased geological and geophysical expenditures in the United States ($19 million) and lower exploration administrative expenses in Other International ($10 million) primarily due to the sale of the Canadian assets.

Impairments include amortization of unproved oil and gas property costs; as well as impairments of proved oil and gas properties; other property, plant and equipment; and other assets. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a DD&A group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by using the Income Approach described in the Fair Value Measurement Topic of the Financial Accounting Standards Board's Accounting Standards Codification (ASC). In certain instances, EOG utilizes accepted bids as the basis for determining fair value.

Impairments of $6,614 million in 2015 increased $5,870 million from $744 million in 2014 primarily due to increased impairments of proved properties and other assets in the United States ($5,959 million), primarily due to commodity price declines; and increased amortization of unproved property costs in the United States ($112 million), which was caused by higher amortization rates being applied to undeveloped leasehold costs in response to the significant decrease in commodity prices and an increase in EOG's estimates of undeveloped properties not expected to be developed before lease expiration; partially offset by decreased impairments of proved properties in the United Kingdom ($156 million) and Argentina ($43 million). Proved property and other asset impairments in the United States were primarily related to legacy natural gas assets and marginal liquids plays. EOG recorded impairments of proved properties; other property, plant and equipment; and other assets of $6,326 million and $575 million in 2015 and 2014, respectively.

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

Taxes other than income in 2015 decreased $336 million to $422 million (6.6% of wellhead revenues) from $758 million (6.0% of wellhead revenues) in 2014. The decrease in taxes other than income was primarily due to decreases in severance/production taxes ($307 million), primarily as a result of decreased wellhead revenues and lower ad valorem/property taxes ($17 million), both in the United States.

Other income, net, was $2 million in 2015 compared to other expense, net, of $45 million in 2014. The increase of $47 million was primarily due to a decrease in net foreign currency transaction losses and decreased deferred compensation expense.

EOG recognized an income tax benefit of $2,397 million in 2015 compared to an income tax expense of $2,080 million in 2014 primarily due to impairments recognized in the United States in 2015. The net effective tax rate for 2015 decreased to 35% from 42% in the prior year primarily due to the effects of recording valuation allowances in the United Kingdom and deferred tax in the United States related to undistributed foreign earnings in 2014.

2014 compared to 2013. During 2014, operating expenses of $12,794 million were $1,982 million higher than the $10,812 million incurred during 2013. The following table presents the costs per Boe for the years ended December 31, 2014 and 2013:

	2014	2013
Lease and Well	$ 6.53	$ 5.94
Transportation Costs	4.48	4.58
DD&A -		
Oil and Gas Properties	17.90	18.79
Other Property, Plant and Equipment	0.53	0.55
G&A	1.85	1.87
Net Interest Expense	0.93	1.26
Total (1)	**$ 32.22**	**$ 32.99**

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2014 compared to 2013 are set forth below. See "Net Operating Revenues" above for a discussion of production volumes.

Lease and well expenses of $1,416 million in 2014 increased $310 million from $1,106 million in 2013 primarily due to higher operating and maintenance costs ($209 million), increased workover expenditures ($69 million) and increased lease and well administrative expenses ($32 million), all in the United States.

Transportation costs of $972 million in 2014 increased $119 million from $853 million in 2013 primarily due to increased transportation costs related to production from the Eagle Ford ($99 million) and the Rocky Mountain area ($15 million).

DD&A expenses in 2014 increased $396 million to $3,997 million from $3,601 million in 2013. DD&A expenses associated with oil and gas properties in 2014 were $384 million higher than in 2013 primarily due to increased production in the United States ($630 million), partially offset by lower unit rates in the United States ($191 million) and Canada ($37 million) and a decrease in production in Canada ($31 million). Unit rates in the United States decreased primarily due to upward reserve revisions and reserves added at lower costs as a result of increased efficiencies.

G&A expenses of $402 million in 2014 were $54 million higher than 2013 primarily due to higher costs associated with supporting expanding operations.

Net interest expense of $201 million in 2014 was $34 million lower than 2013 primarily due to repayment of the $400 million aggregate principal amount of the 6.125% Senior Notes due 2013, the Subsidiary Debt and the Floating Rate Notes ($31 million), as well as an increase in capitalized interest across the company ($8 million). This was partially offset by interest expense on the Notes issued in March 2014 ($10 million).

Gathering and processing costs increased $38 million to $146 million in 2014 compared to $108 million in 2013 primarily due to increased activities in the Eagle Ford.

Exploration costs of $184 million in 2014 increased $23 million from $161 million in 2013 primarily due to increased geological and geophysical expenditures in the United States.

Impairments of $744 million in 2014 increased $457 million from $287 million in 2013 primarily due to increased impairments of proved properties in the United Kingdom ($351 million), the United States ($145 million) and Argentina ($39 million); and increased amortization of unproved property costs in the United States ($54 million); partially offset by decreased impairments of proved properties in Canada ($67 million) and Trinidad ($14 million); and lower impairments of other assets in the United States ($46 million). EOG recorded impairments of proved properties; other property, plant and equipment; and other assets of $575 million and $172 million in 2014 and 2013, respectively. The 2014 and 2013 amounts include impairments of $503 million and $7 million, respectively, related to certain assets as a result of declining commodity prices and using accepted bids for determining fair value.

Taxes other than income in 2014 increased $134 million to $758 million (6.0% of wellhead revenues) from $624 million (5.8% of wellhead revenues) in 2013. The increase in taxes other than income was primarily due to increases in severance/production taxes ($112 million) primarily as a result of increased wellhead revenues and higher ad valorem/property taxes ($34 million) in the United States, partially offset by an increase in credits available to EOG in 2014 for Texas high-cost gas severance tax rate reductions ($11 million).

Other expense, net, was $45 million in 2014 compared to $3 million in 2013. The increase of $42 million was primarily due to net foreign currency transaction losses.

Income tax provision of $2,080 million in 2014 increased $840 million from $1,240 million in 2013 due primarily to higher pretax income. The net effective tax rate for 2014 increased to 42% from 36% in the prior year. The net effective tax rate for 2014 exceeded the United States statutory tax rate (35%) due primarily to valuation allowances in the United Kingdom and deferred tax in the United States related to EOG's undistributed foreign earnings. EOG no longer asserts that foreign earnings will remain permanently reinvested abroad and therefore recorded deferred tax of $250 million on the accumulated balance of such earnings in the fourth quarter of 2014.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2015, were funds generated from operations, net proceeds from issuances of long-term debt, proceeds from asset sales, excess tax benefits from stock-based compensation and net commercial paper borrowings and borrowings under other uncommitted credit facilities. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; repayments of debt; dividend payments to stockholders; and purchases of treasury stock in connection with stock compensation plans.

2015 compared to 2014. Net cash provided by operating activities of $3,595 million in 2015 decreased $5,054 million from $8,649 million in 2014 primarily reflecting a decrease in wellhead revenues ($6,188 million), unfavorable changes in working capital and other assets and liabilities ($591 million) and an increase in net cash paid for interest expense ($25 million), partially offset by a decrease in cash operating expenses ($741 million), a favorable change in the net cash received from the settlement of financial commodity derivative contracts ($696 million) and a decrease in net cash paid for income taxes ($302 million).

Net cash used in investing activities of $5,320 million in 2015 decreased by $2,194 million from $7,514 million in 2014 primarily due to a decrease in additions to oil and gas properties ($2,795 million); and a decrease in additions to other property, plant and equipment ($439 million); partially offset by unfavorable changes in working capital associated with investing activities ($603 million); a decrease in proceeds from sales of assets ($377 million) and the release of restricted cash in 2014 ($60 million).

Net cash provided by financing activities of $371 million in 2015 included net proceeds from the issuance of the Notes ($990 million), net commercial paper borrowings ($260 million), excess tax benefits from stock-based compensation ($26 million) and proceeds from stock options exercised and employee stock purchase plan activity ($23 million). Cash used in financing activities in 2015 included repayments of long-term debt ($500 million), cash dividend payments ($367 million) and purchases of treasury stock in connection with stock compensation plans ($49 million).

2014 compared to 2013. Net cash provided by operating activities of $8,649 million in 2014 increased $1,320 million from $7,329 million in 2013 primarily reflecting an increase in wellhead revenues ($1,837 million), favorable changes in working capital and other assets and liabilities ($391 million) and a decrease in net cash paid for interest expense ($38 million), partially offset by an increase in cash operating expenses ($662 million), an unfavorable change in the net cash received from the settlement of financial commodity derivative contracts ($82 million) and an increase in net cash paid for income taxes ($48 million).

Net cash used in investing activities of $7,514 million in 2014 increased by $1,199 million from $6,315 million in 2013 primarily due to an increase in additions to oil and gas properties ($823 million); an increase in additions to other property, plant and equipment ($364 million); and a decrease in proceeds from sales of assets ($191 million); partially offset by the release of restricted cash ($126 million) and favorable changes in working capital associated with investing activities ($52 million).

Net cash used in financing activities of $328 million during 2014 included repayments of long-term debt ($500 million), cash dividend payments ($280 million), purchases of treasury stock in connection with stock compensation plans ($127 million) and the settlement of a foreign currency swap ($32 million). Cash provided by financing activities in 2014 included net proceeds from the issuances of long-term debt ($496 million), excess tax benefits from stock-based compensation ($99 million) and proceeds from stock options exercised and employee stock purchase plan activity ($22 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2015, 2014 and 2013 (in millions):

	2015	2014	2013
Expenditure Category			
Capital			
Exploration and Development Drilling	$ 3,289	$ 5,543	$ 5,070
Facilities	765	1,367	974
Leasehold Acquisitions [(1)]	134	370	414
Property Acquisitions	481	139	120
Capitalized Interest	42	57	49
Subtotal	4,711	7,476	6,627
Exploration Costs	149	184	161
Dry Hole Costs	15	49	75
Exploration and Development Expenditures	4,875	7,709	6,863
Asset Retirement Costs	53	196	134
Total Exploration and Development Expenditures	4,928	7,905	6,997
Other Property, Plant and Equipment	288	727	364
Total Expenditures	**$ 5,216**	**$ 8,632**	**$ 7,361**

(1) Leasehold acquisitions included $5 million in both 2014 and 2013 related to non-cash property exchanges.

Exploration and development expenditures of $4,875 million for 2015 were $2,834 million lower than the prior year primarily due to decreased exploration and development drilling expenditures in the United States ($2,189 million) and Other International ($74 million); decreased facilities expenditures ($553 million), decreased leasehold acquisitions ($232 million), decreased exploration geological and geophysical expenditures ($19 million), and decreased capitalized interest ($11 million), all in the United States. These decreases were partially offset by increased property acquisitions ($342 million) in the United States. The 2015 exploration and development expenditures of $4,875 million included $4,007 million in development drilling and facilities, $481 million in property acquisitions, $345 million in exploration and $42 million in capitalized interest. The 2014 exploration and development expenditures of $7,709 million included $6,804 million in development drilling and facilities, $709 million in exploration, $139 million in property acquisitions and $57 million in capitalized interest. The 2013 exploration and development expenditures of $6,863 million included $5,952 million in development drilling and facilities, $742 million in exploration, $120 million in property acquisitions and $49 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

Commodity Derivative Contracts. Presented below is a comprehensive summary of EOG's natural gas derivative contracts at February 25, 2016, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Derivative Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2016		
March 1, 2016 through August 31, 2016	60,000	$ 2.49

Financing

EOG's debt-to-total capitalization ratio was 34% at December 31, 2015, compared to 25% at December 31, 2014. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

At December 31, 2015 and 2014, respectively, EOG had outstanding $6,390 million and $5,890 million aggregate principal amount of senior notes which had estimated fair values of $6,524 million and $6,242 million, respectively. The estimated fair value was based upon quoted market prices and, where such prices were not available, other observable inputs regarding interest rates available to EOG at year-end. EOG's debt is at fixed interest rates. While changes in interest rates affect the fair value of EOG's senior notes, such changes do not expose EOG to material fluctuations in earnings or cash flow.

During 2015, EOG funded its capital program primarily by utilizing cash provided by operating activities, proceeds from the issuance of the Notes, cash provided by borrowings from its commercial paper program and proceeds from asset sales. While EOG maintains a $2.0 billion commercial paper program, the maximum outstanding at any time during 2015 was $641 million, and the amount outstanding at year-end was $260 million. There were no amounts outstanding under uncommitted credit facilities during 2015. The average borrowings outstanding under the commercial paper program and the uncommitted credit facilities were $81 million and zero, respectively, during the year 2015. EOG considers this excess availability, which is backed by its 2015 Agreement described in Note 2 to Consolidated Financial Statements, to be sufficient to meet its ongoing operating needs.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2015, (in thousands):

Contractual Obligations [1]	**Total**	**2016**	**2017 - 2018**	**2019 - 2020**	**2021 & Beyond**
Current and Long-Term Debt	$ 6,390,000	$ 400,000	$ 950,000	$ 1,900,000	$ 3,140,000
Capital Lease	45,064	6,579	13,318	14,172	10,995
Non-Cancelable Operating Leases	421,189	104,459	113,953	74,842	127,935
Interest Payments on Long-Term Debt and Capital Lease	1,545,348	258,575	471,314	294,335	521,124
Transportation and Storage Service Commitments [2]	4,070,003	936,118	1,482,446	882,849	768,590
Drilling Rig Commitments [3]	144,540	85,933	57,107	—	1,500
Seismic Purchase Obligations	2,216	2,216	—	—	—
Fracturing Services Obligations	201,501	105,957	88,287	5,412	1,845
Other Purchase Obligations	91,309	40,967	33,834	15,417	1,091
Total Contractual Obligations	**$ 12,911,170**	**$ 1,940,804**	**$ 3,210,259**	**$ 3,187,027**	**$ 4,573,080**

(1) This table does not include the liability for unrecognized tax benefits, EOG's pension or postretirement benefit obligations or liability for dismantlement, abandonment and asset retirement obligations (see Notes 6, 7 and 15, respectively, to Consolidated Financial Statements).

(2) Amounts shown are based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2015. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results of operations of EOG.

(3) Amounts shown represent minimum future expenditures for drilling rig services. EOG's expenditures for drilling rig services will exceed such minimum amounts to the extent EOG utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract or if EOG utilizes drilling rigs in addition to the drilling rigs subject to the particular contractual commitment (for example, pursuant to the exercise of an option to utilize additional drilling rigs provided for in the governing contract).

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities or partnerships, often referred to as variable interest entities (VIE) or special purpose entities (SPE), are generally established for the purpose of facilitating off-balance sheet arrangements or other limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions or any other "off-balance sheet arrangement" (as defined in Item 303(a)(4)(ii) of Regulation S-K) during any of the periods covered by this report and currently has no intention of participating in any such transaction or arrangement in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2015, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Trinidad, the United Kingdom, China, Canada and Argentina. The foreign currency most significant to EOG's operations during 2015 was the British pound. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against foreign currency exchange rate risk.

Outlook

Pricing. Crude oil and natural gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of, and demand for, crude oil and condensate, NGL and natural gas, the availabilities of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in crude oil and condensate, NGLs, natural gas, ammonia and methanol prices in the future. The market price of crude oil and condensate, NGLs and natural gas in 2016 will impact the amount of cash generated from operating activities, which will in turn impact EOG's financial position. As of February 12, 2016, the average 2016 U.S. New York Mercantile Exchange (NYMEX) crude oil and natural gas prices were $34.97 per barrel and $2.23 per MMBtu, respectively, representing declines of 28% and 17%, respectively, from the average NYMEX prices in 2015. See ITEM 1A, Risk Factors.

Based on EOG's tax position, EOG's price sensitivity in 2016 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately $65 million for net income and $81 million for cash flows from operating activities. Including the impact of EOG's 2016 natural gas derivative contracts (exclusive of options) and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2016 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $15 million for net income and $18 million for cash flows from operating activities. For information regarding EOG's crude oil and natural gas financial commodity derivative contracts at February 25, 2016, see "Derivative Transactions" above.

Capital. EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States. In particular, EOG will be focused on United States crude oil drilling activity in its Eagle Ford, Delaware Basin and Bakken plays where it generates its highest rates-of-return. To further enhance the economics of these plays, EOG expects to continue to improve well performance and lower drilling and completion costs through efficiency gains and lower service costs.

The total anticipated 2016 capital expenditures of approximately $2.4 billion to $2.6 billion, excluding acquisitions, is structured to maintain EOG's strategy of capital discipline by funding its exploration, development and exploitation activities primarily from available internally generated cash flows, net proceeds from the New Notes and cash on hand. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its 2015 Agreement and equity and debt offerings.

Operations. In 2016, both total production and total crude oil production are expected to decline slightly from 2015 levels. In 2016, EOG expects to continue to focus on reducing operating costs through efficiency improvements and lower service costs.

Summary of Critical Accounting Policies

EOG prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. EOG identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of EOG's financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of EOG's most critical accounting policies:

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves in accordance with United States Securities and Exchange Commission regulations, which directly impact financial accounting estimates, including depreciation, depletion and amortization and impairments of proved properties and related assets. Proved reserves represent estimated quantities of crude oil and condensate, NGLs and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

Oil and Gas Exploration Costs

EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of EOG's calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the ASC. The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Depreciation, depletion and amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

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

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted bids as the basis for determining fair value. Estimates of undiscounted future cash flows require significant judgment. Crude oil and natural gas prices have exhibited significant volatility in the past, and EOG expects that volatility to continue in the future. During the five years ended December 31, 2015, West Texas Intermediate crude oil spot prices have fluctuated from approximately $34.55 per barrel to $113.39 per barrel, and Henry Hub natural gas spot prices have ranged from approximately $1.63 per MMBtu to $8.15 per MMBtu. EOG's proved reserves estimates, including the timing of future production, are also subject to significant assumptions and judgment, and are frequently revised (upwards and downwards) as more information becomes available. In the future, if actual crude oil and/or natural gas prices and/or actual production diverge negatively from EOG's current estimates, impairment charges may be necessary.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate. Significant assumptions used in estimating future taxable income include future oil and gas prices and changes in tax rates. Changes in such assumptions could materially affect the recognized amounts of valuation allowances.

Stock-Based Compensation

In accounting for stock-based compensation, judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. Assumptions regarding expected volatility of EOG's common stock, the level of risk-free interest rates, expected dividend yields on EOG's common stock, the expected term of the awards, expected volatility of the price of shares of EOG's peer companies and other valuation inputs are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized on the Consolidated Statements of Income and Comprehensive Income.

Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production and costs, 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, reduce or otherwise control operating and capital costs, 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, supplies of, 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 maximize 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 and condensate, natural gas liquids, 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 the acquisition of licenses, leases and properties, 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 21 of this Annual Report on Form 10-K and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the duration and extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The information required by this Item is incorporated by reference from Item 7 of this report, specifically the information set forth under the captions "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. ***Financial Statements and Supplementary Data***

The information required by this Item is included in this report as set forth in the "Index to Financial Statements" on page F-1 and is incorporated by reference herein.

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

ITEM 9A. ***Controls and Procedures***

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of December 31, 2015. EOG's disclosure controls and procedures are designed to provide reasonable assurance that information that is required to be disclosed in the reports EOG files or submits under the Exchange Act is accumulated and communicated to EOG's management, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the United States Securities and Exchange Commission. Based on that evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of December 31, 2015.

Management's Annual Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2015. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013).* Based on this assessment and such criteria, EOG's management believes that EOG's internal control over financial reporting was effective as of December 31, 2015. See also "Management's Responsibility for Financial Reporting" appearing on page F-2 of this report, which is incorporated herein by reference.

The report of EOG's independent registered public accounting firm relating to the consolidated financial statements and effectiveness of internal control over financial reporting is set forth on page F-3 of this report.

There were no changes in EOG's internal control over financial reporting that occurred during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

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

None.

PART III

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

The information required by this Item is incorporated by reference from (i) EOG's Definitive Proxy Statement with respect to its 2016 Annual Meeting of Stockholders to be filed not later than April 29, 2016 and (ii) Item 1 of this report, specifically the information therein set forth under the caption "Executive Officers of the Registrant."

Pursuant to Rule 303A.10 of the New York Stock Exchange and Item 406 of Regulation S-K promulgated under the Securities Exchange Act of 1934, as amended, EOG has adopted a Code of Business Conduct and Ethics for Directors, Officers and Employees (Code of Conduct) that applies to all EOG directors, officers and employees, including EOG's principal executive officer, principal financial officer and principal accounting officer. EOG has also adopted a Code of Ethics for Senior Financial Officers (Code of Ethics) that, along with EOG's Code of Conduct, applies to EOG's principal executive officer, principal financial officer, principal accounting officer and controllers.

You can access the Code of Conduct and Code of Ethics on the Corporate Governance page under "About EOG" on EOG's website at www.eogresources.com, and any EOG stockholder who so requests may obtain a printed copy of the Code of Conduct and Code of Ethics by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose any amendments to the Code of Conduct or Code of Ethics, and any waivers with respect to the Code of Conduct or Code of Ethics granted to EOG's principal executive officer, principal financial officer, principal accounting officer, any of our controllers or any of our other employees performing similar functions, on its website at www.eogresources.com within four business days of the amendment or waiver. In such case, the disclosure regarding the amendment or waiver will remain available on EOG's website for at least 12 months after the initial disclosure. There have been no waivers granted with respect to EOG's Code of Conduct or Code of Ethics.

ITEM 11. ***Executive Compensation***

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2016 Annual Meeting of Stockholders to be filed not later than April 29, 2016. The Compensation Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2016 Annual Meeting of Stockholders to be filed not later than April 29, 2016.

On February 24, 2014, EOG's Board of Directors (Board) approved a two-for-one stock split in the form of a stock dividend (payable to stockholders of record as of March 17, 2014, and paid on March 31, 2014) and corresponding adjustments to EOG's equity compensation plans. All share amounts set forth below have been restated to reflect the two-for-one stock split and such adjustments.

Equity Compensation Plan Information

Stock Plans Approved by EOG Stockholders. EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the 2008 Plan was approved, pursuant to which the number of shares of common stock available for future grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units, performance stock, performance units and other stock-based awards under the 2008 Plan was increased by an additional 13.8 million shares, to an aggregate maximum of 25.8 million shares plus shares underlying forfeited or canceled grants under the prior stock plans referenced in the 2008 Plan document. At the 2013 Annual Meeting of Stockholders in May 2013, EOG's stockholders approved the Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Amended and Restated Plan). As more fully discussed in the Amended and Restated Plan document, the Amended and Restated Plan, among other things, authorizes an additional 31.0 million shares of EOG common stock for grant under the plan and extends the expiration date of the plan to May 2023. Under the Amended and Restated Plan, grants may be made to employees and non-employee members of EOG's Board.

At the 2010 Annual Meeting, an amendment to the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP) was approved to increase the shares available for grant by 2.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG.

The 1993 Nonemployee Directors Stock Option Plan has also been approved by EOG's stockholders. Upon the effective date of the 2008 Plan, no further grants were made under the 1993 Nonemployee Directors Stock Option Plan. Plans that have not been approved by EOG's stockholders are described below.

Stock Plans Not Approved by EOG Stockholders. In December 2008, the Board approved the amendment and continuation of the 1996 Deferral Plan as the "EOG Resources, Inc. 409A Deferred Compensation Plan" (Deferral Plan). Under the Deferral Plan (as subsequently amended), payment of up to 50% of base salary and 100% of annual cash bonus, director's fees, vestings of restricted stock units granted to non-employee directors (and dividends credited thereon) under the 2008 Plan and 401(k) refunds (as defined in the Deferral Plan) may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if shares of EOG common stock were purchased at the closing stock price on the date of deferral. Dividends are credited quarterly and treated as if reinvested in EOG common stock. Payment of the phantom stock account is made in actual shares of EOG common stock in accordance with the Deferral Plan and the individual's deferral election. A total of 540,000 shares of EOG common stock have been authorized by the Board and registered for issuance under the Deferral Plan. As of December 31, 2015, 269,508 phantom shares had been issued.

The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by EOG's stockholders and those plans not approved by EOG's stockholders, in each case as of December 31, 2015.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights		(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity Compensation Plans Approved by EOG Stockholders	10,743,819 (1)	$	67.98	25,247,925 (2)
Equity Compensation Plans Not Approved by EOG Stockholders	241,789 (3)		N/A	270,492 (4)
Total	**10,985,608**	**$**	**67.98**	**25,518,417**

(1) Does not include 1,626,436 outstanding restricted stock units and 371,496 outstanding performance units, for which shares of EOG common stock will be issued, on a one-for-one basis, upon the vesting of such grants.

(2) Consists of (i) 24,679,703 shares remaining available for issuance under the 2008 Plan and (ii) 568,222 shares remaining available for purchase under the ESPP. Pursuant to the fungible share design of the 2008 Plan, each share issued as a SAR or stock option under the 2008 Plan counts as 1.0 share against the aggregate plan share limit, and each share issued as a "full value award" (i.e., as restricted stock, restricted stock units, performance stock or performance units) counts as 2.45 shares against the aggregate plan share limit. Thus, from the 24,679,703 shares remaining available for issuance under the 2008 Plan, (i) the maximum number of shares we could issue as SAR and stock option awards is 24,679,703 (i.e., if all shares remaining available for issuance under the 2008 Plan are issued as SAR and stock option awards) and (ii) the maximum number of shares we could issue as full value awards is 10,073,348 (i.e., if all shares remaining available for issuance under the 2008 Plan are issued as full value awards).

(3) Consists of shares of EOG common stock to be issued in accordance with the Deferral Plan and participant deferral elections (i.e., in respect of the 241,789 phantom shares issued and outstanding under the Deferral Plan as of December 31, 2015).

(4) Represents phantom shares that remain available for issuance under the Deferral Plan.

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

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2016 Annual Meeting of Stockholders to be filed not later than April 29, 2016.

ITEM 14. *Principal Accounting Fees and Services*

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2016 Annual Meeting of Stockholders to be filed not later than April 29, 2016.

PART IV

ITEM 15. *Exhibits, Financial Statement Schedules*

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedule

See "Index to Financial Statements" set forth on page F-1.

(a)(3), (b) Exhibits

See pages E-1 through E-6 for a listing of the exhibits.

EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), were prepared by management, which is responsible for the integrity, objectivity and fair presentation of such financial statements. The statements have been prepared in conformity with generally accepted accounting principles in the United States of America and, accordingly, include some amounts that are based on the best estimates and judgments of management.

EOG's management is also responsible for establishing and maintaining adequate internal control over financial reporting as well as designing and implementing programs and controls to prevent and detect fraud. The system of internal control of EOG is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. This system consists of 1) entity level controls, including written policies and guidelines relating to the ethical conduct of business affairs, 2) general computer controls and 3) process controls over initiating, authorizing, recording, processing and reporting transactions. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

The adequacy of EOG's financial controls and the accounting principles employed by EOG in its financial reporting are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of EOG. Moreover, EOG's independent registered public accounting firm and internal auditors have full, free, separate and direct access to the Audit Committee and meet with the committee periodically to discuss accounting, auditing and financial reporting matters.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2015. In making this assessment, EOG used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013)*. These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment and those criteria, management believes that EOG maintained effective internal control over financial reporting as of December 31, 2015.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements of EOG, audit EOG's internal control over financial reporting and issue a report thereon. In the conduct of the audits, Deloitte & Touche LLP was given unrestricted access to all financial records and related data, including all minutes of meetings of stockholders, the Board of Directors and committees of the Board of Directors. Management believes that all representations made to Deloitte & Touche LLP during the audits were valid and appropriate. Their audits were made in accordance with the standards of the Public Company Accounting Oversight Board (United States). Their report appears on page F-3.

WILLIAM R. THOMAS	TIMOTHY K. DRIGGERS
Chairman of the Board and	*Vice President and Chief*
Chief Executive Officer	*Financial Officer*

Houston, Texas
February 25, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
EOG Resources, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EOG Resources, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

<u>/s/ DELOITTE & TOUCHE LLP</u>

Houston, Texas
February 25, 2016

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

Year Ended December 31	2015	2014	2013
Net Operating Revenues			
Crude Oil and Condensate	$ 4,934,562	$ 9,742,480	$ 8,300,647
Natural Gas Liquids	407,658	934,051	773,970
Natural Gas	1,061,038	1,916,386	1,681,029
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	61,924	834,273	(166,349)
Gathering, Processing and Marketing	2,253,135	4,046,316	3,643,749
Gains (Losses) on Asset Dispositions, Net	(8,798)	507,590	197,565
Other, Net	47,909	54,244	56,507
Total	8,757,428	18,035,340	14,487,118
Operating Expenses			
Lease and Well	1,182,282	1,416,413	1,105,978
Transportation Costs	849,319	972,176	853,044
Gathering and Processing Costs	146,156	145,800	107,871
Exploration Costs	149,494	184,388	161,346
Dry Hole Costs	14,746	48,490	74,655
Impairments	6,613,546	743,575	286,941
Marketing Costs	2,385,982	4,126,060	3,648,840
Depreciation, Depletion and Amortization	3,313,644	3,997,041	3,600,976
General and Administrative	366,594	402,010	348,312
Taxes Other Than Income	421,744	757,564	623,944
Total	15,443,507	12,793,517	10,811,907
Operating Income (Loss)	(6,686,079)	5,241,823	3,675,211
Other Income (Expense), Net	1,916	(45,050)	(2,865)
Income (Loss) Before Interest Expense and Income Taxes	(6,684,163)	5,196,773	3,672,346
Interest Expense			
Incurred	279,234	258,628	284,599
Capitalized	(41,841)	(57,170)	(49,139)
Net Interest Expense	237,393	201,458	235,460
Income (Loss) Before Income Taxes	(6,921,556)	4,995,315	3,436,886
Income Tax Provision (Benefit)	(2,397,041)	2,079,828	1,239,777
Net Income (Loss)	**$(4,524,515)**	**$ 2,915,487**	**$ 2,197,109**
Net Income (Loss) Per Share			
Basic	$ (8.29)	$ 5.36	$ 4.07
Diluted	$ (8.29)	$ 5.32	$ 4.02
Dividends Declared per Common Share	$ 0.670	$ 0.585	$ 0.375
Average Number of Common Shares			
Basic	545,697	543,443	540,341
Diluted	545,697	548,539	546,227
Comprehensive Income (Loss)			
Net Income (Loss)	$(4,524,515)	$ 2,915,487	$ 2,197,109
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	(11,517)	(437,728)	(29,395)
Other, Net of Tax	1,235	(1,162)	5,334
Other Comprehensive Loss	(10,282)	(438,890)	(24,061)
Comprehensive Income (Loss)	**$(4,534,797)**	**$ 2,476,597**	**$ 2,173,048**

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

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

At December 31	2015	2014
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 718,506	$ 2,087,213
Accounts Receivable, Net	930,610	1,779,311
Inventories	598,935	706,597
Assets from Price Risk Management Activities	—	465,128
Income Taxes Receivable	40,704	71,621
Deferred Income Taxes	147,812	19,618
Other	155,677	286,533
Total	2,592,244	5,416,021
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	50,613,241	46,503,532
Other Property, Plant and Equipment	3,986,610	3,750,958
Total Property, Plant and Equipment	54,599,851	50,254,490
Less: Accumulated Depreciation, Depletion and Amortization	(30,389,130)	(21,081,846)
Total Property, Plant and Equipment, Net	24,210,721	29,172,644
Other Assets	172,279	174,022
Total Assets	**$ 26,975,244**	**$ 34,762,687**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 1,471,953	$ 2,860,548
Accrued Taxes Payable	93,618	140,098
Dividends Payable	91,546	91,594
Deferred Income Taxes	—	110,743
Current Portion of Long-Term Debt	6,579	6,579
Other	155,591	174,746
Total	1,819,287	3,384,308
Long-Term Debt	6,653,685	5,903,354
Other Liabilities	971,335	939,497
Deferred Income Taxes	4,587,902	6,822,946
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 550,150,823 Shares and 549,028,374 Shares Issued at December 31, 2015 and 2014, respectively	205,502	205,492
Additional Paid in Capital	2,923,461	2,837,150
Accumulated Other Comprehensive Loss	(33,338)	(23,056)
Retained Earnings	9,870,816	14,763,098
Common Stock Held in Treasury, 292,179 Shares and 733,517 Shares at December 31, 2015 and 2014, respectively	(23,406)	(70,102)
Total Stockholders' Equity	12,943,035	17,712,582
Total Liabilities and Stockholders' Equity	**$ 26,975,244**	**$ 34,762,687**

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Thousands, Except Per Share Data)

	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Stockholders' Equity
Balance at December 31, 2012	$ 202,720	$2,500,340	$ 439,895	$10,175,631	$ (33,822)	$ 13,284,764
Net Income	—	—	—	2,197,109	—	2,197,109
Common Stock Issued Under Stock Plans	6	38,723	—	—	—	38,729
Common Stock Dividends Declared, $0.38 Per Share	—	—	—	(204,463)	—	(204,463)
Other Comprehensive Income	—	—	(24,061)	—	—	(24,061)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(79,641)	—	—	47,427	(32,214)
Excess Tax Benefit from Stock-Based Compensation	—	55,831	—	—	—	55,831
Restricted Stock and Restricted Stock Units, Net	6	(2,974)	—	—	(28,454)	(31,422)
Stock-Based Compensation Expenses	—	134,467	—	—	—	134,467
Treasury Stock Issued as Compensation	—	133	—	—	(414)	(281)
Balance at December 31, 2013	202,732	2,646,879	415,834	12,168,277	(15,263)	15,418,459
Net Income	—	—	—	2,915,487	—	2,915,487
Common Stock Issued Under Stock Plans	8	22,252	—	—	—	22,260
Common Stock Dividends Declared, $0.59 Per Share	—	—	—	(320,666)	—	(320,666)
Other Comprehensive Loss	—	—	(438,890)	—	—	(438,890)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(30,470)	—	—	(96,962)	(127,432)
Excess Tax Benefit from Stock-Based Compensation	—	99,459	—	—	—	99,459
Restricted Stock and Restricted Stock Units, Net	18	(43,109)	—	—	43,091	—
Stock-Based Compensation Expenses	—	144,842	—	—	—	144,842
Common Stock Issued - Stock Split	2,734	(2,734)	—	—	—	—
Treasury Stock Issued as Compensation	—	31	—	—	(968)	(937)
Balance at December 31, 2014	205,492	2,837,150	(23,056)	14,763,098	(70,102)	17,712,582
Net Income	—	—	—	(4,524,515)	—	(4,524,515)
Common Stock Issued Under Stock Plans	5	15,366	—	—	—	15,371
Common Stock Dividends Declared, $0.67 Per Share	—	—	—	(367,767)	—	(367,767)
Other Comprehensive Loss	—	—	(10,282)	—	—	(10,282)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(41,342)	—	—	(129)	(41,471)
Excess Tax Benefit from Stock-Based Compensation	—	26,058	—	—	—	26,058
Restricted Stock and Restricted Stock Units, Net	5	(44,339)	—	—	44,334	—
Stock-Based Compensation Expenses	—	130,577	—	—	—	130,577
Treasury Stock Issued as Compensation	—	(9)	—	—	2,491	2,482
Balance at December 31, 2015	**$ 205,502**	**$2,923,461**	**$ (33,338)**	**$ 9,870,816**	**$ (23,406)**	**$ 12,943,035**

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

Year Ended December 31	2015	2014	2013
Cash Flows from Operating Activities			
Reconciliation of Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net Income (Loss)	$ (4,524,515)	$ 2,915,487	$ 2,197,109
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	3,313,644	3,997,041	3,600,976
Impairments	6,613,546	743,575	286,941
Stock-Based Compensation Expenses	130,577	145,086	134,055
Deferred Income Taxes	(2,482,307)	1,704,946	874,765
(Gains) Losses on Asset Dispositions, Net	8,798	(507,590)	(197,565)
Other, Net	11,896	48,138	11,072
Dry Hole Costs	14,746	48,490	74,655
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	(61,924)	(834,273)	166,349
Net Cash Received from Settlements of Commodity Derivative Contracts	730,114	34,007	116,361
Excess Tax Benefits from Stock-Based Compensation	(26,058)	(99,459)	(55,831)
Other, Net	12,532	13,009	18,205
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	641,412	84,982	(23,613)
Inventories	58,450	(161,958)	53,402
Accounts Payable	(1,409,197)	543,630	178,701
Accrued Taxes Payable	11,798	16,486	75,142
Other Assets	118,143	(14,448)	(109,567)
Other Liabilities	(66,257)	75,420	(20,382)
Changes in Components of Working Capital Associated with Investing and Financing Activities	499,767	(103,414)	(51,361)
Net Cash Provided by Operating Activities	3,595,165	8,649,155	7,329,414
Investing Cash Flows			
Additions to Oil and Gas Properties	(4,725,150)	(7,519,667)	(6,697,091)
Additions to Other Property, Plant and Equipment	(288,013)	(727,138)	(363,536)
Proceeds from Sales of Assets	192,807	569,332	760,557
Changes in Restricted Cash	—	60,385	(65,814)
Changes in Components of Working Capital Associated with Investing Activities	(499,900)	103,523	51,106
Net Cash Used in Investing Activities	(5,320,256)	(7,513,565)	(6,314,778)
Financing Cash Flows			
Net Commercial Paper Borrowings	259,718	—	—
Long-Term Debt Borrowings	990,225	496,220	—
Long-Term Debt Repayments	(500,000)	(500,000)	(400,000)
Settlement of Foreign Currency Swap	—	(31,573)	—
Dividends Paid	(367,005)	(279,695)	(199,178)
Excess Tax Benefits from Stock-Based Compensation	26,058	99,459	55,831
Treasury Stock Purchased	(48,791)	(127,424)	(63,784)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	22,690	22,249	38,730
Debt Issuance Costs	(5,951)	(895)	—
Repayment of Capital Lease Obligation	(6,156)	(5,966)	(5,780)
Other, Net	133	(109)	255
Net Cash Provided by (Used in) Financing Activities	370,921	(327,734)	(573,926)
Effect of Exchange Rate Changes on Cash	(14,537)	(38,852)	1,064
Increase (Decrease) in Cash and Cash Equivalents	(1,368,707)	769,004	441,774
Cash and Cash Equivalents at Beginning of Year	2,087,213	1,318,209	876,435
Cash and Cash Equivalents at End of Year	**$ 718,506**	**$ 2,087,213**	**$ 1,318,209**

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

1. Summary of Significant Accounting Policies

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

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt. The carrying values of cash and cash equivalents, commodity derivative contracts, accounts receivable and accounts payable approximate fair value (see Notes 2 and 12).

Cash and Cash Equivalents. EOG records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Oil and Gas Operations. EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made (see Note 16). Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on EOG's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. If applicable, EOG utilizes accepted bids as the basis for determining fair value.

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

Arrangements for sales of crude oil and condensate, natural gas liquids (NGLs) and natural gas are evidenced by signed contracts with determinable market prices, and revenues are recorded when production is delivered. A significant majority of these products are sold to purchasers who have investment-grade credit ratings and material credit losses have been rare. Revenues are recorded on the entitlement method based on EOG's percentage ownership of current production. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold on that owner's behalf may differ from that owner's ownership percentage. Under entitlement accounting, a receivable is recorded when underproduction occurs and a payable is recorded when overproduction occurs. Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as gathering fees associated with gathering third-party natural gas and revenues from sales of EOG-owned sand.

Other Property, Plant and Equipment. Other property, plant and equipment consists of gathering and processing assets, compressors, buildings and leasehold improvements, crude-by-rail assets, sand mine and sand processing assets, computer hardware and software, vehicles, and furniture and fixtures. Other property, plant and equipment is generally depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from 3 years to 45 years.

Capitalized Interest Costs. Interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. The amount capitalized is an allocation of the interest cost incurred during the reporting period. Capitalized interest is computed only during the exploration and development phases and ceases once production begins. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings.

Accounting for Risk Management Activities. Derivative instruments are recorded on the balance sheet as either an asset or liability measured at fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ended December 31, 2015, EOG elected not to designate any of its financial commodity derivative instruments as accounting hedges and, accordingly, changes in the fair value of these outstanding derivative instruments are recognized as gains or losses in the period of change. The gains or losses are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact of settled contracts is reflected as cash flows from operating activities. EOG was party to a foreign currency swap transaction and an interest rate swap transaction, both of which were accounted for using the hedge accounting method. EOG employs net presentation of derivative assets and liabilities for financial reporting purposes when such assets and liabilities are with the same counterparty and subject to a master netting arrangement. See Note 12.

Income Taxes. Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate (see Note 6).

Foreign Currency Translation. The United States dollar is the functional currency for all of EOG's consolidated subsidiaries except for its Canadian subsidiaries, for which the functional currency is the Canadian dollar, and its United Kingdom subsidiary, for which the functional currency is the British pound. For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. See Notes 4 and 17.

Net Income (Loss) Per Share. Basic net income (loss) per share is computed on the basis of the weighted-average number of common shares outstanding during the period. Diluted net income (loss) per share is computed based upon the weighted-average number of common shares outstanding during the period plus the assumed issuance of common shares for all potentially dilutive securities (see Note 9).

Stock-Based Compensation. EOG measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (see Note 7).

Recently Issued Accounting Standards. In November 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes " (ASU 2015-17), which simplifies the presentation of deferred taxes in a classified balance sheet by eliminating the requirement to separate deferred income tax liabilities and assets into current and noncurrent amounts. Instead, ASU 2015-17 requires that all deferred tax liabilities and assets be shown as noncurrent in a classified balance sheet. ASU 2015-17 is effective for financial statements issued for interim and annual periods beginning after December 15, 2016, and early adoption is permitted. EOG does not intend to early-adopt ASU 2015-17 and does not expect the new standard to have a material impact on its consolidated financial statements and related disclosures.

In July 2015, the FASB issued ASU 2015-11, "Accounting for Inventory" (ASU 2015-11), which requires entities to measure most inventory at lower of cost or net realizable value. ASU 2015-11 defines net realizable value as "the estimated selling prices in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation." ASU 2015-11 is effective prospectively for interim and annual periods beginning after December 15, 2016. EOG is reviewing the requirements of the new standard and does not believe that the adoption of ASU 2015-11 will have a material impact on its consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03, "Interest - Computation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03), which changes the presentation of debt issuance costs in financial statements. Under ASU 2015-03, an entity will present debt issuance costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of such costs will be presented as a component of interest expense. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015. Early adoption is permitted. Because ASU 2015-03 does not address debt issuance costs related to line-of-credit arrangements, in August 2015, the FASB issued ASU 2015-15 "Interest - Computation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" (ASU 2015-15). ASU 2015-15 provides that, in the absence of authoritative guidance in ASU 2015-03, the United States Securities and Exchange Commission would not object to an entity deferring and presenting debt issuance costs related to a line-of-credit arrangement as an asset and subsequently amortizing the deferred debt issuance costs over the term of the line-of-credit arrangement. EOG does not expect the adoption of ASU 2015-03 and ASU 2015-15 to have a material impact on its consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU 2014-09, "Revenue From Contracts With Customers" (ASU 2014-09), which will require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will supersede most current guidance related to revenue recognition when it becomes effective. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. The FASB originally intended ASU 2014-09 to be effective for interim and annual reporting periods beginning after December 15, 2016, and permits adoption through the use of either the full retrospective approach or a modified retrospective approach. In July 2015, the FASB issued an update which delays by one year the effective date of ASU 2014-09 and allows for early adoption as of the original effective date. EOG does not intend to early-adopt ASU 2014-09 and has not determined which transition method it will use. EOG continues to analyze ASU 2014-09 to determine what impact the new standard will have on its consolidated financial statements and related disclosures.

2. Long-Term Debt

Long-Term Debt at December 31, 2015 and 2014 consisted of the following (in thousands):

	2015	2014
Commercial Paper	$ 259,718	$ —
2.95% Senior Notes due 2015	—	500,000
2.500% Senior Notes due 2016	400,000	400,000
5.875% Senior Notes due 2017	600,000	600,000
6.875% Senior Notes due 2018	350,000	350,000
5.625% Senior Notes due 2019	900,000	900,000
4.40% Senior Notes due 2020	500,000	500,000
2.45% Senior Notes due 2020	500,000	500,000
4.100% Senior Notes due 2021	750,000	750,000
2.625% Senior Notes due 2023	1,250,000	1,250,000
3.15% Senior Notes due 2025	500,000	—
6.65% Senior Notes due 2028	140,000	140,000
3.90% Senior Notes due 2035	500,000	—
Long-Term Debt	6,649,718	5,890,000
Capital Lease Obligation	45,064	51,221
Less: Current Portion of Long-Term Debt	6,579	6,579
Unamortized Debt Discount	34,518	31,288
Total Long-Term Debt	**$ 6,653,685**	**$ 5,903,354**

At December 31, 2015, the aggregate annual maturities of long-term debt (excluding capital lease obligations) were $400 million in 2016, $600 million in 2017, $350 million in 2018, $900 million in 2019 and $1 billion in 2020. At December 31, 2015 and 2014, EOG had $260 million and zero, respectively, of outstanding short-term borrowings under the commercial paper program and no outstanding borrowings under uncommitted credit facilities.

During 2015 and 2014, EOG utilized commercial paper and short-term borrowings under uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. The average borrowings outstanding under the commercial paper program were $81 million and $12 million during the years ended December 31, 2015 and 2014, respectively. The average borrowings outstanding under the uncommitted credit facilities were zero and $0.1 million during the years ended December 31, 2015 and 2014, respectively. The weighted average interest rates for commercial paper borrowings were 0.51% and 0.25% for the years 2015 and 2014, respectively, and were 0.70% for uncommitted credit facility borrowings for the year 2014.

At December 31, 2015, the $400 million aggregate principal amount of its 2.500% Senior Notes due 2016 (2016 Notes) and $260 million aggregate principal amount of commercial paper borrowings were classified as long-term debt based upon EOG's intent and ability to ultimately replace such amount with other long-term debt.

On January 14, 2016, EOG closed its sale of $750 million aggregate principal amount of its 4.15% Senior Notes due 2026 and $250 million aggregate principal amount of its 5.10% Senior Notes due 2036 (collectively, the New Notes). Interest on the New Notes is payable semi-annually in arrears on January 15 and July 15 of each year beginning on July 15, 2016. Net proceeds from the New Notes offering totaled approximately $991 million and were used to repay the 2016 Notes when they matured on February 1, 2016, and for general corporate purposes, including repayment of outstanding commercial paper borrowings and funding of future capital expenditures.

On July 21, 2015, EOG entered into a new $2.0 billion senior unsecured Revolving Credit Agreement (2015 Agreement) with domestic and foreign lenders. The 2015 Agreement replaces EOG's $2.0 billion senior unsecured Revolving Credit Agreement, dated as of October 11, 2011, which had a scheduled maturity date of October 11, 2016 (2011 Agreement). There were no borrowings or letters of credit outstanding under the 2011 Agreement as of the closing of the 2015 Agreement and the termination of the 2011 Agreement. The 2015 Agreement has a scheduled maturity date of July 21, 2020, and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods subject to certain terms and conditions. Advances under the 2015 Agreement will accrue interest based, at EOG's option, on either the London InterBank Offered Rate plus an applicable margin (Eurodollar rate) or the base rate (as defined in the 2015 Agreement) plus an applicable margin. Consistent with the terms of the 2011 Agreement, the 2015 Agreement contains representations, warranties, covenants and events of default that are customary for investment-grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a debt-to-total capitalization ratio of no greater than 65%. At December 31, 2015, there were no borrowings or letters of credit outstanding under the 2015 Agreement. The Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2015 Agreement, would have been 1.33% and 3.50%, respectively.

On June 1, 2015, EOG repaid upon maturity the $500 million aggregate principal amount of its 2.95% Senior Notes due 2015.

On March 17, 2015, EOG closed its sale of $500 million aggregate principal amount of its 3.15% Senior Notes due 2025 and $500 million aggregate principal amount of its 3.90% Senior Notes due 2035 (together, the Notes). Interest on the Notes is payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2015. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes.

3. Stockholders' Equity

Common Stock. In September 2001, EOG's Board of Directors (Board) authorized the purchase of an aggregate maximum of 10 million shares of Common Stock that superseded all previous authorizations. At December 31, 2015, 6,386,200 shares remained available for purchase under this authorization. EOG last purchased shares of its Common Stock under this authorization in March 2003. In addition, shares of Common Stock are from time to time withheld by, or returned to, EOG in satisfaction of tax withholding obligations arising upon the exercise of employee stock options or stock-settled stock appreciation rights (SARs), the vesting of restricted stock or restricted stock unit grants or in payment of the exercise price of employee stock options. Such shares withheld or returned do not count against the Board authorization discussed above. Shares purchased, withheld and returned are held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock-based compensation plans and any other approved transactions or activities for which such shares of Common Stock may be required.

On February 24, 2014, EOG's Board approved a two-for-one stock split in the form of a stock dividend, which was paid on March 31, 2014, to stockholders of record as of March 17, 2014.

On August 5, 2014, the Board increased the quarterly cash dividend on the common stock by 34% to $0.1675 per share, effective beginning with the dividend paid on October 31, 2014, to stockholders of record as of October 17, 2014. On February 24, 2014, the Board increased the quarterly cash dividend on the common stock by 33% to $0.125 per share, effective beginning with the dividend paid on April 30, 2014, to stockholders of record as of April 16, 2014. The Board increased the quarterly cash dividend on the Common Stock to $0.0938 per share on February 13, 2013, effective beginning with the dividend paid on April 30, 2013, to stockholders of record as of April 16, 2013.

The following summarizes Common Stock activity for each of the years ended December 31, 2013, 2014 and 2015 (in thousands):

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2012	543,916	(652)	543,264
Common Stock Issued Under Stock-Based Compensation Plans	2,206	—	2,206
Treasury Stock Purchased (1)	—	(854)	(854)
Common Stock Issued Under Employee Stock Purchase Plan	256	—	256
Treasury Stock Issued Under Stock-Based Compensation Plans	—	1,300	1,300
Balance at December 31, 2013	546,378	(206)	546,172
Common Stock Issued Under Stock-Based Compensation Plans	2,448	—	2,448
Treasury Stock Purchased (1)	—	(1,209)	(1,209)
Common Stock Issued Under Employee Stock Purchase Plan	202	—	202
Treasury Stock Issued Under Stock-Based Compensation Plans	—	682	682
Balance at December 31, 2014	549,028	(733)	548,295
Common Stock Issued Under Stock-Based Compensation Plans	1,019	—	1,019
Treasury Stock Purchased (1)	—	(581)	(581)
Common Stock Issued Under Employee Stock Purchase Plan	104	121	225
Treasury Stock Issued Under Stock-Based Compensation Plans	—	901	901
Balance at December 31, 2015	550,151	(292)	549,859

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

Preferred Stock. EOG currently has one authorized series of preferred stock. As of December 31, 2015, there were no shares of preferred stock outstanding.

4. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) includes certain transactions that have generally been reported in the Consolidated Statements of Stockholders' Equity. The components of Accumulated Other Comprehensive Income (Loss) at December 31, 2015 and 2014 consisted of the following (in thousands):

	Foreign Currency Translation Adjustment	Other	Total
December 31, 2013	$ 417,707	$ (1,873)	$ 415,834
Other comprehensive loss before reclassifications	(54,484)	(918)	(55,402)
Amounts reclassified out of other comprehensive income (loss)	(383,244) (1)	246 (2)	(382,998)
Tax effects	—	(490)	(490)
Other comprehensive income (loss)	(437,728)	(1,162)	(438,890)
December 31, 2014	(20,021)	(3,035)	(23,056)
Other comprehensive loss before reclassifications	(11,517)	(129)	(11,646)
Amounts reclassified out of other comprehensive income (loss)	—	1,572 (3)	1,572
Tax effects	—	(208)	(208)
Other comprehensive income (loss)	(11,517)	1,235	(10,282)
December 31, 2015	$ (31,538)	$ (1,800)	$ (33,338)

(1) Reclassified to Net Income (Loss) - Gains (Losses) on Asset Dispositions, Net. See Note 17.
(2) Includes $107 thousand reclassified to Net Income (Loss) - Interest Expense in connection with the settlement of a foreign currency swap and an interest rate swap and $139 thousand reclassified to Net Income (Loss) - General and Administrative related to certain EOG pension plans (see Note 7).
(3) Reclassified to Net Income (Loss) - General and Administrative. Related to certain EOG pension plans. See Note 7.

No significant amount was reclassified out of Accumulated Other Comprehensive Income (Loss) during the year ended December 31, 2013.

5. Other Income (Expense), Net

Other income, net, for 2015 included equity income from investments in ammonia plants in Trinidad ($9 million), a downward adjustment to deferred compensation expense ($6 million), interest income ($3 million) and net foreign currency transaction losses ($(17) million). Other expense, net, for 2014 included net foreign currency transaction losses ($(34) million), losses on dispositions of warehouse stock ($15 million) and equity income from investments in ammonia plants in Trinidad ($8 million). Other expense, net, for 2013 included losses on dispositions of warehouse stock ($23 million), net foreign currency transaction gains ($12 million), equity income from investments in ammonia plants in Trinidad ($11 million) and interest income ($6 million) primarily related to sales and use tax refunds.

6. Income Taxes

The principal components of EOG's net deferred income tax liabilities at December 31, 2015 and 2014 were as follows (in thousands):

	2015	2014
Current Deferred Income Tax Assets (Liabilities)		
Deferred Compensation Plans	$ 38,559	$ —
Alternative Minimum Tax Credit Carryforward	93,316	—
Foreign Net Operating Loss	47,786	49,865
Foreign Valuation Allowance	(35,536)	(30,247)
Other	3,687	—
Total Net Current Deferred Income Tax Assets	**$ 147,812**	**$ 19,618**
Noncurrent Deferred Income Tax Assets (Liabilities)		
Foreign Oil and Gas Exploration and Development Costs Deducted for Tax Under Book Depreciation, Depletion and Amortization	$ (57,569)	$ (141,643)
Foreign Net Operating Loss	443,010	487,876
Foreign Valuation Allowances	(380,104)	(349,704)
Foreign Other	1,506	4,096
Total Net Noncurrent Deferred Income Tax Assets	**$ 6,843**	**$ 625**
Current Deferred Income Tax (Asset) Liabilities		
Commodity Hedging Contracts	$ —	$ 166,109
Deferred Compensation Plans	—	(48,207)
Accrued Expenses and Liabilities	—	(5,643)
Other	—	(1,516)
Total Net Current Deferred Income Tax Liabilities	**$ —**	**$ 110,743**
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 5,299,817	$ 7,634,297
Non-Producing Leasehold Costs	(53,026)	(44,236)
Seismic Costs Capitalized for Tax	(162,240)	(158,157)
Equity Awards	(140,663)	(127,541)
Capitalized Interest	98,242	97,739
Alternative Minimum Tax Credit Carryforward	(685,189)	(793,126)
Undistributed Foreign Earnings	258,403	249,861
Other	(27,442)	(35,891)
Total Net Noncurrent Deferred Income Tax Liabilities	**$ 4,587,902**	**$ 6,822,946**
Total Net Deferred Income Tax Liabilities	**$ 4,433,247**	**$ 6,913,446**

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

	2015	2014	2013
United States	$ (6,840,119)	$ 5,161,232	$ 3,268,727
Foreign	(81,437)	(165,917)	168,159
Total	**$ (6,921,556)**	**$ 4,995,315**	**$ 3,436,886**

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

	2015	2014	2013
Current:			
Federal	$ 21,719	$ 269,326	$ 207,777
State	9,404	22,835	22,856
Foreign	54,143	82,721	134,379
Total	85,266	374,882	365,012
Deferred:			
Federal	(2,362,926)	1,608,706	915,994
State	(127,444)	29,056	26,305
Foreign	8,063	67,184	(67,534)
Total	(2,482,307)	1,704,946	874,765
Income Tax Provision (Benefit)	**$ (2,397,041)**	**$ 2,079,828**	**$ 1,239,777**

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

	2015	2014	2013
Statutory Federal Income Tax Rate	35.00%	35.00%	35.00%
State Income Tax, Net of Federal Benefit	1.11	0.68	0.93
Income Tax Provision Related to Foreign Operations	(1.31)	(0.12)	0.23
Canadian Divestiture	—	(3.46)	—
Undistributed Foreign Earnings	—	4.94	—
Foreign Valuation Allowances	—	6.47	—
Foreign Oil and Gas Impairments	—	(1.90)	—
Other	(0.17)	0.03	(0.09)
Effective Income Tax Rate	34.63%	41.64%	36.07%

The effective tax rate of 35% in 2015 was lower than the prior year rate of 42% primarily due to the effects of recording valuation allowances in the United Kingdom and deferred taxes in the United States on undistributed foreign earnings in 2014.

Deferred tax assets are recorded for certain tax benefits, including tax net operating losses (NOLs) and tax credit carryforwards, provided that management assesses the utilization of such assets to be "more likely than not." Management assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to use the existing deferred tax assets. On the basis of this evaluation, EOG has recorded valuation allowances for the portion of certain foreign and state deferred tax assets that management does not believe are more likely than not to be realized.

The principal components of EOG's rollforward of valuation allowances for deferred tax assets were as follows (in thousands):

	2015	2014	2013
Beginning Balance	$ 463,018	$ 223,599	$ 199,743
Increase (1)	146,602	392,729	43,422
Decrease (2)	(4,315)	(1,424)	(4,967)
Other (3)	(99,178)	(151,886)	(14,599)
Ending Balance	**$ 506,127**	**$ 463,018**	**$ 223,599**

(1) Increase in valuation allowance related to the generation of tax net operating losses and other deferred tax assets.
(2) Decrease in valuation allowance associated with adjustments to certain deferred tax assets and their related allowance.
(3) Represents dispositions/revisions/foreign exchange rate variances and the effect of statutory income tax rate changes.

The balance of unrecognized tax benefits at December 31, 2015, was zero. When applicable, EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. Currently, there are no amounts of interest or penalties recognized on the Consolidated Statements of Income and Comprehensive Income or on the Consolidated Balance Sheets. EOG does not anticipate that the amount of the unrecognized tax benefits will significantly change during the next twelve months. EOG and its subsidiaries file income tax returns and are subject to tax audits in the United States and various state, local and foreign jurisdictions. EOG's earliest open tax years in its principal jurisdictions are as follows: United States federal (2011), Canada (2011), United Kingdom (2014), Trinidad (2002) and China (2008).

EOG's foreign subsidiaries' undistributed earnings of approximately $2 billion at December 31, 2015, are no longer considered to be permanently reinvested outside the United States and, accordingly, EOG has cumulatively recorded $258 million of United States federal and state deferred income taxes. EOG changed its permanent reinvestment assertion in 2014.

In 2015, EOG utilized alternative minimum tax (AMT) credits of $4 million. Additional AMT credits of $779 million, resulting from AMT paid in prior years, will be carried forward indefinitely until they are used to offset regular income taxes in future periods. The ability of EOG to utilize these AMT credit carryforwards to reduce federal income taxes may become subject to various limitations under the Internal Revenue Code. Such limitations may arise if certain ownership changes (as defined for income tax purposes) were to occur. As of December 31, 2015, management does not believe that an ownership change has occurred which would limit these carryforwards.

As of December 31, 2015, EOG had state income tax NOLs being carried forward of approximately $1.7 billion, which, if unused, expire between 2016 and 2034. During 2015, EOG's United Kingdom subsidiary incurred a tax NOL of approximately $153 million which, along with prior years' NOLs of $764 million, will be carried forward indefinitely. As described above, these NOLs have been evaluated for the likelihood of future utilization, and valuation allowances have been established for the portion of these deferred tax assets that do not meet the "more likely than not" threshold.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) was enacted on December 18, 2015. PATH retroactively extended various temporary individual and business tax incentives for 2015 and in some instances extended certain incentives through 2019. Bonus tax depreciation, a favorable tax incentive for EOG, was extended from 2015 through 2019.

7. Employee Benefit Plans

Stock-Based Compensation

During 2015, EOG maintained various stock-based compensation plans as discussed below. EOG recognizes compensation expense on grants of stock options, SARs, restricted stock and restricted stock units, performance units and performance stock, and grants made under the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP). Stock-based compensation expense is calculated based upon the grant date estimated fair value of the awards, net of forfeitures, based upon EOG's historical employee turnover rate. Compensation expense is amortized over the shorter of the vesting period or the period from date of grant until the date the employee becomes eligible to retire without company approval.

Stock-based compensation expense is included on the Consolidated Statements of Income and Comprehensive Income based upon the job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years ended December 31, 2015, 2014 and 2013 was as follows (in millions):

	2015	2014	2013
Lease and Well	$ 44	$ 41	$ 35
Gathering and Processing Costs	1	1	1
Exploration Costs	26	27	27
General and Administrative	60	76	71
Total	$ 131	$ 145	$ 134

The Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) provides for grants of stock options, SARs, restricted stock and restricted stock units, performance stock and performance units, and other stock-based awards. At December 31, 2015, approximately 24.7 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares or treasury shares to the extent treasury shares are available.

During 2015, 2014 and 2013, EOG issued shares in connection with stock option/SAR exercises, restricted stock grants, restricted stock unit releases and ESPP purchases. EOG recognized, as an adjustment to APIC, federal income tax benefits of $26 million, $99 million and $56 million for 2015, 2014 and 2013, respectively, related to the exercise of stock options/SARs and the release of restricted stock and restricted stock units.

Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan. Participants in EOG's stock-based compensation plans (including the 2008 Plan) have been or may be granted options to purchase shares of Common Stock. In addition, participants in EOG's stock plans (including the 2008 Plan) have been or may be granted SARs, representing the right to receive shares of Common Stock based on the appreciation in the stock price from the date of grant on the number of SARs granted. Stock options and SARs are granted at a price not less than the market price of the Common Stock on the date of grant. Stock options and SARs granted vest on a graded vesting schedule up to four years from the date of grant based on the nature of the grants and as defined in individual grant agreements. Terms for stock options and SARs granted have not exceeded a maximum term of seven years. EOG's ESPP allows eligible employees to semi-annually purchase, through payroll deductions, shares of Common Stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employee's pay (subject to certain ESPP limits) during each of the two six-month offering periods each year.

The fair value of stock option grants and SAR grants is estimated using the Hull-White II binomial option pricing model. The fair value of ESPP grants is estimated using the Black-Scholes-Merton model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $56 million, $62 million and $53 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2015, 2014 and 2013 were as follows:

	Stock Options/SARs			ESPP		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Weighted Average Fair Value of Grants	$ 21.88	$ 30.75	$ 27.35	$ 21.21	$ 21.65	$ 15.06
Expected Volatility	38.03%	35.28%	35.86%	32.08%	25.03%	29.89%
Risk-Free Interest Rate	0.83%	0.95%	0.78%	0.12%	0.08%	0.11%
Dividend Yield	0.85%	0.61%	0.40%	0.73%	0.46%	0.60%
Expected Life	5.3 years	5.2 years	5.5 years	0.5 years	0.5 years	0.5 years

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's Common Stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock option, SAR and ESPP grants.

The following table sets forth the stock option and SAR transactions for the years ended December 31, 2015, 2014 and 2013 (stock options and SARs in thousands):

	2015		2014		2013	
	Number of Stock Options/ SARs	Weighted Average Grant Price	Number of Stock Options/ SARs	Weighted Average Grant Price	Number of Stock Options/ SARs	Weighted Average Grant Price
Outstanding at January 1	10,493	$ 64.96	10,452	$ 54.43	12,438	$ 42.91
Granted	2,037	69.99	2,146	101.55	2,268	83.70
Exercised [(1)]	(1,518)	47.64	(1,718)	45.68	(4,046)	35.62
Forfeited	(268)	80.31	(387)	68.95	(208)	50.78
Outstanding at December 31	10,744	67.98	10,493	64.96	10,452	54.43
Stock Options/SARs Exercisable at December 31	5,993	57.96	5,287	49.40	4,638	43.95

(1) The total intrinsic value of stock options/SARs exercised during the years 2015, 2014 and 2013 was $60 million, $95 million and $151 million, respectively. The intrinsic value is based upon the difference between the market price of the Common Stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2015, there were 10.4 million stock options/SARs vested or expected to vest with a weighted average grant price of $67.52 per share, an intrinsic value of $52 million and a weighted average remaining contractual life of 4.1 years.

The following table summarizes certain information for the stock options and SARs outstanding and exercisable at December 31, 2015 (stock options and SARs in thousands):

	Stock Options/SARs Outstanding				Stock Options/SARs Exercisable			
Range of Grant Prices	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value[(1)]	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value [(1)]
$22.00 to $ 44.99	2,184	2	$ 41.08		2,182	2	$ 41.08	
45.00 to 56.99	2,672	3	52.37		2,229	3	51.64	
57.00 to 69.99	2,019	7	69.13		51	4	62.11	
70.00 to 84.99	1,832	4	84.25		936	4	84.36	
85.00 to 116.99	2,037	5	101.49		595	5	101.61	
	10,744	4	67.98	$ 117,424	5,993	3	57.96	$ 107,950

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

At December 31, 2015, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $100 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.8 years.

At December 31, 2015, approximately 568,000 shares of Common Stock remained available for issuance under the ESPP. The following table summarizes ESPP activities for the years ended December 31, 2015, 2014 and 2013 (in thousands, except number of participants):

	2015	2014	2013
Approximate Number of Participants	1,963	1,991	1,844
Shares Purchased	225	202	256
Aggregate Purchase Price	$ 15,045	$ 14,927	$ 14,015

Restricted Stock and Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. The restricted stock and restricted stock units generally vest five years after the date of grant, except for certain bonus grants, and as defined in individual grant agreements. Upon vesting of restricted stock, shares of Common Stock are released to the employee. Upon vesting, restricted stock units are converted into shares of Common Stock and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $69 million, $74 million and $72 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2015, 2014 and 2013 (shares and units in thousands):

	2015		2014		2013	
	Number of Shares and Units	**Weighted Average Grant Date Fair Value**	**Number of Shares and Units**	**Weighted Average Grant Date Fair Value**	**Number of Shares and Units**	**Weighted Average Grant Date Fair Value**
Outstanding at January 1	5,394	$ 64.39	7,358	$ 49.54	7,636	$ 45.53
Granted	1,044	77.94	1,132	98.72	1,294	76.04
Released [1]	(1,331)	51.52	(2,761)	105.24	(1,368)	52.39
Forfeited	(199)	74.56	(335)	62.55	(204)	48.55
Outstanding at December 31 [2]	4,908	70.35	5,394	64.39	7,358	49.54

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2015, 2014 and 2013 was $109 million, $291 million and $101 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.

(2) The total intrinsic value of restricted stock and restricted stock units outstanding at December 31, 2015 and 2014 was approximately $347 million and $497 million, respectively.

At December 31, 2015, unrecognized compensation expense related to restricted stock and restricted stock units totaled $156 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.5 years.

Performance Units and Performance Stock. EOG grants performance units and/or performance stock to its executive officers. As more fully discussed in the grant agreements, the performance metric applicable to these performance-based grants is EOG's total shareholder return over a three-year performance period relative to the total shareholder return of a designated group of peer companies. Upon the application of the performance multiple at the completion of the performance period, a minimum of zero and a maximum of 810,000 performance units/shares could be outstanding (based on the number of performance units/shares outstanding as of December 31, 2015). Subject to the termination provisions set forth in the grant agreements and the applicable performance multiple, the grants of performance units/shares will "cliff" vest five years from the date of grant. The fair value of the performance units and performance stock is estimated using a Monte Carlo simulation. Stock-based compensation expense related to performance unit and performance stock grants totaled $5 million, $9 million and $9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Weighted average fair values and valuation assumptions used to value performance unit and performance stock grants during the years ended December 31, 2015, 2014 and 2013 were as follows:

	2015	2014	2013
Weighted Average Fair Value of Grants	$ 80.64	$ 119.27	$ 100.34
Expected Volatility	29.35%	32.18%	33.63%
Risk-Free Interest Rate	1.07%	1.18%	0.79%

Expected volatility is based on the term-matched historical volatility over the simulated term, which is calculated as the time between the grant date and the end of the performance period. The risk-free interest rate is based on a 3.26 year zero-coupon risk-free interest rate derived from the Treasury Constant Maturities yield curve on the grant date.

The following table sets forth performance unit and performance stock transactions for the years ended December 31, 2015, 2014 and 2013 (units and shares in thousands):

	2015		2014		2013	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	333	$ 90.17	261	$ 82.18	142	$ 67.05
Granted	72	80.64	72	119.27	119	100.34
Outstanding at December 31 (1)	405	88.48	333	90.17	261	82.18

(1) The total intrinsic value of performance units and performance stock outstanding at December 31, 2015 and 2014 was $29 million and $31 million, respectively.

At December 31, 2015, unrecognized compensation expense related to performance units and performance stock totaled $6 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 3.3 years.

Pension Plans. EOG has a defined contribution pension plan in place for most of its employees in the United States. EOG's contributions to the pension plan are based on various percentages of compensation and, in some instances, are based upon the amount of the employees' contributions. EOG's total costs recognized for the plan were $36 million, $41 million and $37 million for 2015, 2014 and 2013, respectively.

In addition, EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. EOG's United Kingdom subsidiary maintains a pension plan which includes a non-contributory defined contribution pension plan and a matched defined contribution savings plan. These pension plans are available to most employees of the Trinidadian and United Kingdom subsidiaries. EOG's combined contributions to these plans were $1 million, $5 million and $4 million for 2015, 2014 and 2013, respectively.

For the Trinidadian defined benefit pension plan, the benefit obligation, fair value of plan assets and accrued benefit cost totaled $9 million, $7 million and $0.2 million, respectively, at December 31, 2015, and $14 million, $12 million and $1 million, respectively, at December 31, 2014. In connection with the divestiture of substantially all of its Canadian assets in the fourth quarter of 2014, EOG has elected to terminate the Canadian non-contributory defined benefit pension plan.

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

8. Commitments and Contingencies

Letters of Credit and Guarantees. At December 31, 2015 and 2014, respectively, EOG had standby letters of credit and guarantees outstanding totaling approximately $272 million and $423 million, primarily representing guarantees of payment or performance obligations on behalf of subsidiaries. As of February 25, 2016, there were no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2015, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase obligations, fracturing services obligations, other purchase obligations and transportation and storage service commitments, based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2015, were as follows (in thousands):

	Total Minimum Commitments
2016	$ 1,275,650
2017	994,328
2018	781,299
2019	547,299
2020	431,221
2021 and beyond	900,961
	$ 4,930,758

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2042. Rental expenses associated with existing leases amounted to $229 million, $237 million and $191 million for 2015, 2014 and 2013, respectively.

Contingencies. There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

9. Net Income (Loss) Per Share

The following table sets forth the computation of Net Income (Loss) Per Share for the years ended December 31, 2015, 2014 and 2013 (in thousands, except per share data):

	2015	2014	2013
Numerator for Basic and Diluted Earnings per Share -			
Net Income (Loss)	$ (4,524,515)	$ 2,915,487	$ 2,197,109
Denominator for Basic Earnings per Share -			
Weighted Average Shares	545,697	543,443	540,341
Potential Dilutive Common Shares -			
Stock Options/SARs	—	2,526	2,316
Restricted Stock/Units and Performance Units/Stock	—	2,570	3,570
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	545,697	548,539	546,227
Net Income (Loss) Per Share			
Basic	$ (8.29)	$ 5.36	$ 4.07
Diluted	$ (8.29)	$ 5.32	$ 4.02

The diluted earnings per share calculation excludes stock options, SARs, restricted stock and units and performance units and stock that were anti-dilutive. Shares underlying the excluded stock options and SARs totaled 10.2 million, 0.7 million and 0.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. For the year ended December 31, 2015, 5.3 million shares of restricted stock and restricted stock units and performance units and performance stock were excluded.

10. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the years ended December 31, 2015, 2014 and 2013 (in thousands):

	2015	2014	2013
Interest, Net of Capitalized Interest	$ 222,088	$ 197,383	$ 235,854
Income Taxes, Net of Refunds Received	$ 41,108	$ 342,741	$ 294,739

EOG's accrued capital expenditures at December 31, 2015, 2014 and 2013 were $416 million, $972 million and $731 million, respectively.

Non-cash investing activities for each of the years ended December 31, 2014 and 2013 included non-cash additions of $5 million to EOG's oil and gas properties as a result of property exchanges.

11. Business Segment Information

EOG's operations are all crude oil and natural gas exploration and production related. The Segment Reporting Topic of the ASC establishes standards for reporting information about operating segments in annual financial statements. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker, or decision-making group, in deciding how to allocate resources and in assessing performance. EOG's chief operating decision-making process is informal and involves the Chairman of the Board and Chief Executive Officer and other key officers. This group routinely reviews and makes operating decisions related to significant issues associated with each of EOG's major producing areas in the United States, Trinidad, the United Kingdom, China and Canada. For segment reporting purposes, the chief operating decision maker considers the major United States producing areas to be one operating segment.

As previously reported, during the fourth quarter of 2014, EOG completed the sale of substantially all of its Canadian operations (see Note 17). As a result, information relating to EOG's remaining Canadian operations has been included in the Other International segment and prior year amounts have been reclassified to conform to current year presentation. Financial information by reportable segment is presented below as of and for the years ended December 31, 2015, 2014 and 2013 (in thousands):

	United States	Trinidad	Other International [1]	Total
2015				
Crude Oil and Condensate	$ 4,917,731	$ 13,122	$ 3,709	$ 4,934,562
Natural Gas Liquids	407,570	—	88	407,658
Natural Gas	637,452	368,639	54,947	1,061,038
Gains on Mark-to-Market Commodity Derivative Contracts	61,924	—	—	61,924
Gathering, Processing and Marketing	2,254,477	(1,342)	—	2,253,135
Gains (Losses) on Asset Dispositions, Net	(12,176)	393	2,985	(8,798)
Other, Net	47,464	(3)	448	47,909
Net Operating Revenues [2]	8,314,442	380,809	62,177	8,757,428
Depreciation, Depletion and Amortization	3,139,863	154,853	18,928	3,313,644
Operating Income (Loss)	(6,566,282)	175,658	(295,455)	(6,686,079)
Interest Income	1,913	389	1,167	3,469
Other Income (Expense)	6,461	8,780	(16,794)	(1,553)
Net Interest Expense	274,606	1,400	(38,613)	237,393
Income (Loss) Before Income Taxes	(6,832,514)	183,427	(272,469)	(6,921,556)
Income Tax Provision (Benefit)	(2,463,213)	63,502	2,670	(2,397,041)
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,495,730	102,358	112,316	4,710,404
Total Property, Plant and Equipment, Net	23,593,995	350,766	265,960	24,210,721
Total Assets	25,351,908	886,826	736,510	26,975,244

	United States	Trinidad	Other International (1)	Total
2014				
Crude Oil and Condensate	$ 9,526,149	$ 29,604	$ 186,727	$ 9,742,480
Natural Gas Liquids	924,454	—	9,597	934,051
Natural Gas	1,321,175	483,071	112,140	1,916,386
Gains on Mark-to-Market Commodity Derivative Contracts	834,273	—	—	834,273
Gathering, Processing and Marketing	4,040,024	6,064	228	4,046,316
Gains on Asset Dispositions, Net	96,339	—	411,251	507,590
Other, Net	49,950	37	4,257	54,244
Net Operating Revenues (3)	16,792,364	518,776	724,200	18,035,340
Depreciation, Depletion and Amortization	3,684,943	188,592	123,506	3,997,041
Operating Income (Loss)	5,074,911	277,471	(110,559)	5,241,823
Interest Income	849	253	1,137	2,239
Other Income (Expense)	(14,953)	8,712	(41,048)	(47,289)
Net Interest Expense	269,166	—	(67,708)	201,458
Income (Loss) Before Income Taxes	4,791,641	286,436	(82,762)	4,995,315
Income Tax Provision	1,837,185	98,559	144,084	2,079,828
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	7,133,727	76,138	261,312	7,471,177
Total Property, Plant and Equipment, Net	28,391,741	382,719	398,184	29,172,644
Total Assets	32,871,398	865,674	1,025,615	34,762,687
2013				
Crude Oil and Condensate	$ 8,035,358	$ 40,379	$ 224,910	$ 8,300,647
Natural Gas Liquids	761,535	—	12,435	773,970
Natural Gas	1,100,808	477,103	103,118	1,681,029
Losses on Mark-to-Market Commodity Derivative Contracts	(166,349)	—	—	(166,349)
Gathering, Processing and Marketing	3,636,209	6,064	1,476	3,643,749
Gains on Asset Dispositions, Net	93,876	1,119	102,570	197,565
Other, Net	51,713	24	4,770	56,507
Net Operating Revenues (4)	13,513,150	524,689	449,279	14,487,118
Depreciation, Depletion and Amortization	3,223,596	181,990	195,390	3,600,976
Operating Income (Loss)	3,543,841	266,329	(134,959)	3,675,211
Interest Income	2,803	336	2,446	5,585
Other Income (Expense)	(29,696)	9,889	11,357	(8,450)
Net Interest Expense	283,209	—	(47,749)	235,460
Income (Loss) Before Income Taxes	3,233,739	276,554	(73,407)	3,436,886
Income Tax Provision (Benefit)	1,161,328	118,270	(39,821)	1,239,777
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	6,133,894	132,984	355,558	6,622,436
Total Property, Plant and Equipment, Net	24,456,383	476,174	1,216,279	26,148,836
Total Assets	27,668,713	986,796	1,918,729	30,574,238

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations.
(2) EOG had sales activity with two significant purchasers in 2015, one totaling $1.7 billion and the other totaling $1.4 billion of consolidated Net Operating Revenues in the United States segment.
(3) EOG had sales activity with two significant purchasers in 2014, one totaling $4.0 billion and the other totaling $3.0 billion of consolidated Net Operating Revenues in the United States segment.
(4) EOG had sales activity with two significant purchasers in 2013, one totaling $3.9 billion and the other totaling $2.0 billion of consolidated Net Operating Revenues in the United States segment.

12. Risk Management Activities

Commodity Price Risks. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk.

During 2015, 2014 and 2013, EOG elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounted for these financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact is reflected in Cash Flows from Operating Activities. During 2015, 2014 and 2013, EOG recognized net gains (losses) on the mark-to-market of financial commodity derivative contracts of $62 million, $834 million and $(166) million, respectively, which included cash received from settlements of crude oil and natural gas derivative contracts of $730 million, $34 million and $116 million, respectively. At December 31, 2015, EOG had no outstanding crude oil or natural gas commodity derivative contracts.

The following table sets forth the amounts and classification of EOG's outstanding derivative financial instruments at December 31, 2015 and 2014, respectively. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

Description	Location on Balance Sheet	Fair Value at December 31, 2015	Fair Value at December 31, 2014
Asset Derivatives			
Crude oil and natural gas derivative contracts - Current portion	Assets from Price Risk Management Activities (1)	$ —	$ 465
Liability Derivatives			
Crude oil and natural gas derivative contracts - Current portion	Liabilities from Price Risk Management Activities (2)	$ —	$ —

(1) The current portion of Assets from Price Risk Management Activities consists of gross assets of $477 million, partially offset by gross liabilities of $12 million, at December 31, 2014.

(2) The current portion of Liabilities from Price Risk Management Activities consists of gross liabilities of $12 million, offset by gross assets of $12 million, at December 31, 2014.

Credit Risk. Notional contract amounts are used to express the magnitude of a financial derivative. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 13). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG renegotiates payment terms and/or requires collateral, parent guarantees or letters of credit to minimize credit risk. At December 31, 2015, EOG's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales included three receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from two petroleum refinery companies and one multinational oil and gas company. The related amounts were collected during early 2016. At December 31, 2014, EOG's net accounts receivable balance related to United States, Canada, Argentina and United Kingdom hydrocarbon sales included two receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from two petroleum refinery companies. The related amounts were collected during early 2015. In 2015 and 2014, all natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary, and all natural gas from EOG's China operations was sold to Petrochina Company Limited.

All of EOG's derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 13 for the aggregate fair value of all derivative instruments that were in a net liability position at December 31, 2014. EOG had no collateral posted and held no collateral at December 31, 2015 and had no collateral posted and held $278 million of collateral at December 31, 2014.

Substantially all of EOG's accounts receivable at December 31, 2015 and 2014 resulted from hydrocarbon sales and/or joint interest billings to third-party companies, including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer or joint interest owner, EOG typically analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2015, credit losses incurred on receivables by EOG have been immaterial.

13. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. An established fair value hierarchy prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. EOG gives consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value.

The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at December 31, 2014. There were no such amounts outstanding at December 31, 2015. Amounts shown in millions.

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At December 31, 2014				
Financial Assets:				
Natural Gas Options/Swaptions	$ —	$ 100	$ —	$ 100
Crude Oil Swaps	—	121	—	121
Crude Oil Options/Swaptions	—	244	—	244

The estimated fair value of crude oil and natural gas derivative contracts (including options/swaptions) was based upon forward commodity price curves based on quoted market prices. Commodity derivative contracts were valued by utilizing an independent third-party derivative valuation provider who uses various types of valuation models, as applicable.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 15.

During 2015, due to the decline in commodity prices, proved oil and gas properties, other property, plant and equipment and other assets with a carrying amount of $9,154 million were written down to their fair value of $2,828 million, resulting in pretax impairment charges of $6,326 million, $4,141 million net of tax. Impairments included domestic legacy natural gas assets and marginal liquids plays and the Conwy crude oil project in the East Irish Sea. During 2014, proved oil and gas properties and other assets with a carrying amount of $968 million were written down to their fair value of $393 million, resulting in pretax impairment charges of $575 million. Included in the $575 million pretax impairment charges were $58 million of impairments of proved oil and gas properties and other assets for which EOG utilized accepted offers from third-party purchasers as the basis for determining fair value. Significant Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

Fair Value of Debt. At December 31, 2015 and 2014, respectively, EOG had outstanding $6,390 million and $5,890 million aggregate principal amount of senior notes, which had estimated fair values of approximately $6,524 million and $6,242 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable (Level 2) inputs regarding interest rates available to EOG at year-end.

14. Accounting for Certain Long-Lived Assets

EOG reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. During 2015, 2014 and 2013, such reviews indicated that unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows primarily due to lower commodity prices and, to a lesser extent, downward reserve revisions, drilling of marginal or uneconomic wells, or development dry holes in certain producing fields. Several impairments over this period were recognized in connection with the signing of purchase and sale agreements. As a result, EOG recorded pretax charges of $6,130 million, $171 million and $73 million in the United States during 2015, 2014 and 2013, respectively, and $196 million, $404 million and $85 million in Other International during 2015, 2014 and 2013, respectively. Additionally, EOG recorded pretax charges of $14 million in Trinidad during 2013. The pretax charges are included in Impairments on the Consolidated Statements of Income and Comprehensive Income. The carrying values for assets determined to be impaired were adjusted to estimated fair value using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted bids as the basis for determining fair value. Amortization and impairments of unproved oil and gas property costs, including amortization of capitalized interest, were $288 million, $168 million and $115 million during 2015, 2014 and 2013, respectively.

15. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the years ended December 31, 2015 and 2014 (in thousands):

	2015	2014
Carrying Amount at Beginning of Period	$ 752,718	$ 761,898
Liabilities Incurred	63,844	123,849
Liabilities Settled [1]	(17,415)	(247,422)
Accretion	31,956	41,489
Revisions	(13,356)	82,885
Foreign Currency Translations	(6,193)	(9,981)
Carrying Amount at End of Period	$ 811,554	$ 752,718
Current Portion	$ 7,651	$ 11,814
Noncurrent Portion	$ 803,903	$ 740,904

(1) Includes settlements related to asset sales.

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

16. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the years ended December 31, 2015, 2014 and 2013 are presented below (in thousands):

	2015	2014	2013
Balance at January 1	$ 17,253	$ 9,211	$ 49,116
Additions Pending the Determination of Proved Reserves	24,640	32,080	52,099
Reclassifications to Proved Properties	(26,659)	(15,946)	(54,505)
Costs Charged to Expense [1]	(6,279)	(8,092)	(35,859)
Foreign Currency Translations	—	—	(1,640)
Balance at December 31	$ 8,955	$ 17,253	$ 9,211

(1) Includes capitalized exploratory well costs charged to either dry hole costs or impairments.

At December 31, 2015, 2014 and 2013, all exploratory well costs had been capitalized for periods of less than one year.

17. Acquisitions and Divestitures

During 2015, EOG completed acquisitions of approximately $481 million primarily to acquire proved crude oil properties and related assets in the Delaware Basin and gathering assets in the North Dakota Bakken.

During 2015, EOG received proceeds of approximately $193 million primarily from sales of gathering and processing assets and other assets. During 2014, EOG received proceeds of approximately $569 million primarily from the divestiture of all its assets in Manitoba and the majority of its assets in Alberta (collectively, the Canadian Sales) and from sales of producing properties and acreage in the Upper Gulf Coast region, the Rocky Mountain area and the Mid-Continent area. The Canadian Sales that closed on or about December 1, 2014, occurred in two separate transactions, an asset sale and the sale of the stock of certain of EOG's Canadian subsidiaries. As these two transactions represented a substantially complete liquidation of EOG's Canadian operations, approximately $383 million of cumulative translation adjustments previously recorded on the Consolidated Balance Sheets was reclassified to the Consolidated Statements of Income and Comprehensive Income. The Canadian Sales also resulted in the release of approximately $150 million of restricted cash related to future abandonment liabilities.

Oil and Gas Producing Activities

The following disclosures are made in accordance with Financial Accounting Standards Board Accounting Standards Update No. 2010-03 "Oil and Gas Reserve Estimates and Disclosures" and the United States Securities and Exchange Commission's (SEC) final rule on "Modernization of Oil and Gas Reporting." During the fourth quarter of 2014, EOG completed the sale of substantially all of its Canadian operations. As a result, information relating to EOG's remaining Canadian operations has been included in the Other International segment and prior year amounts have been reclassified to conform to current year presentation.

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil, natural gas liquids (NGLs) and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. See ITEM 1A, Risk Factors.

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

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

Proved undeveloped reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. PUDs can be recorded in respect of a particular undrilled location only if the location is scheduled, under the then-current drilling and development plan, to be drilled within five years from the date that the PUDs are to be recorded, unless specific factors (such as those described in interpretative guidance issued by the Staff of the SEC) justify a longer timeframe. Likewise, absent any such specific factors, PUDs associated with a particular undeveloped drilling location shall be removed from the estimates of proved reserves if the location is scheduled, under the then-current drilling and development plan, to be drilled on a date that is beyond five years from the date that the PUDs were recorded. EOG has formulated development plans for all drilling locations associated with its PUDs at December 31, 2015. Under these plans, each PUD location will be drilled within five years from the date it was recorded. Estimates for PUDs are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

Analysis of dynamic data is then incorporated to arrive at the estimated fractional recovery of hydrocarbons in place. Data analysis techniques employed include, but are not limited to, well testing analysis, static bottom hole pressure analysis, flowing bottom hole pressure analysis, analysis of historical production trends, pressure transient analysis and rate transient analysis.

Application of proprietary rate transient analysis techniques in low permeability rocks allow for quantification of estimates of contribution to production from both fractures and rock matrix.

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

The process of analyzing static and dynamic data, well completion optimization and the results of early development activities provides the appropriate level of certainty as well as support for the economic producibility of the plays in which PUDs are reflected. EOG has found this approach to be effective based on successful application in analogous reservoirs in low permeability resource plays.

Certain of EOG's Trinidad reserves are held under production sharing contracts where EOG's interest varies with prices and production volumes. Trinidad reserves, as presented on a net basis, assume prices in existence at the time the estimates were made and EOG's estimate of future production volumes. Future fluctuations in prices, production rates or changes in political or regulatory environments could cause EOG's share of future production from Trinidadian reserves to be materially different from that presented.

Estimates of proved reserves at December 31, 2015, 2014 and 2013 were based on studies performed by the engineering staff of EOG. The Engineering and Acquisitions Department is directly responsible for EOG's reserve evaluation process and consists of 11 professionals, all of whom hold, at a minimum, bachelor's degrees in engineering, and five of whom are Registered Professional Engineers. The Vice President, Engineering and Acquisitions is the manager of this department and is the primary technical person responsible for this process. The Vice President, Engineering and Acquisitions holds a Bachelor of Science degree in Petroleum Engineering, has 30 years of experience in reserve evaluations and is a Registered Professional Engineer.

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

Opinions by D&M for the years ended December 31, 2015, 2014 and 2013 covered producing areas containing 86%, 76% and 82%, respectively, of proved reserves of EOG on a net-equivalent-barrel-of-oil basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's Engineering and Acquisitions Department for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil basis, do not differ materially from the estimates prepared by D&M. Such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the Engineering and Acquisitions Department of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG. The report of D&M dated February 1, 2016, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 23.2 to this Annual Report on Form 10-K and incorporated herein by reference.

No major discovery or other favorable or adverse event subsequent to December 31, 2015, is believed to have caused a material change in the estimates of net proved reserves as of that date.

The following tables set forth EOG's net proved reserves at December 31 for each of the four years in the period ended December 31, 2015, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2015, as estimated by the Engineering and Acquisitions Department of EOG:

NET PROVED RESERVE SUMMARY

NET PROVED RESERVES	United States	Trinidad	Other International [1]	Total
Crude Oil (MBbl) [2]				
Net proved reserves at December 31, 2012	671,029	3,028	26,761	700,818
Revisions of previous estimates	57,668	(991)	(6,008)	50,669
Purchases in place	1,097	—	—	1,097
Extensions, discoveries and other additions	230,023	—	731	230,754
Sales in place	(2,337)	—	—	(2,337)
Production	(77,431)	(447)	(2,583)	(80,461)
Net proved reserves at December 31, 2013	880,049	1,590	18,901	900,540
Revisions of previous estimates	28,301	99	(378)	28,022
Purchases in place	9,705	—	—	9,705
Extensions, discoveries and other additions	319,540	—	14	319,554
Sales in place	(4,967)	—	(7,656)	(12,623)
Production	(102,946)	(350)	(2,152)	(105,448)
Net proved reserves at December 31, 2014	1,129,682	1,339	8,729	1,139,750
Revisions of previous estimates	(114,924)	(1)	—	(114,925)
Purchases in place	35,922	—	—	35,922
Extensions, discoveries and other additions	141,310	63	13	141,386
Sales in place	(730)	—	(10)	(740)
Production	(103,400)	(332)	(65)	(103,797)
Net proved reserves at December 31, 2015	**1,087,860**	**1,069**	**8,667**	**1,097,596**
Natural Gas Liquids (MBbl) [2]				
Net proved reserves at December 31, 2012	318,406	—	1,557	319,963
Revisions of previous estimates	12,157	—	(48)	12,109
Purchases in place	1,202	—	—	1,202
Extensions, discoveries and other additions	69,187	—	10	69,197
Sales in place	(1,471)	—	—	(1,471)
Production	(23,479)	—	(315)	(23,794)
Net proved reserves at December 31, 2013	376,002	—	1,204	377,206
Revisions of previous estimates	27,450	—	(7)	27,443
Purchases in place	1,812	—	—	1,812
Extensions, discoveries and other additions	91,683	—	—	91,683
Sales in place	(956)	—	(823)	(1,779)
Production	(29,061)	—	(236)	(29,297)
Net proved reserves at December 31, 2014	466,930	—	138	467,068
Revisions of previous estimates	(113,290)	—	68	(113,222)
Purchases in place	8,251	—	—	8,251
Extensions, discoveries and other additions	49,147	—	—	49,147
Sales in place	(84)	—	(187)	(271)
Production	(28,079)	—	(19)	(28,098)
Net proved reserves at December 31, 2015	**382,875**	**—**	**—**	**382,875**

	United States	Trinidad	Other International (1)	Total
Natural Gas (Bcf) (3)				
Net proved reserves at December 31, 2012	4,036.0	588.2	115.3	4,739.5
Revisions of previous estimates	264.0	(17.4)	30.7	277.3
Purchases in place	5.7	—	—	5.7
Extensions, discoveries and other additions	504.7	79.5	9.9	594.1
Sales in place	(69.4)	—	—	(69.4)
Production	(342.3)	(129.6)	(30.5)	(502.4)
Net proved reserves at December 31, 2013	4,398.7	520.7	125.4	5,044.8
Revisions of previous estimates	252.2	12.9	5.5	270.6
Purchases in place	17.1	—	—	17.1
Extensions, discoveries and other additions	638.3	4.5	4.7	647.5
Sales in place	(52.4)	—	(78.7)	(131.1)
Production	(348.4)	(132.5)	(25.4)	(506.3)
Net proved reserves at December 31, 2014	4,905.5	405.6	31.5	5,342.6
Revisions of previous estimates	(1,453.1)	16.8	5.6	(1,430.7)
Purchases in place	72.3	—	—	72.3
Extensions, discoveries and other additions	306.3	21.7	4.4	332.4
Sales in place	(3.9)	—	(11.1)	(15.0)
Production	(337.3)	(127.5)	(10.9)	(475.7)
Net proved reserves at December 31, 2015	**3,489.8**	**316.6**	**19.5**	**3,825.9**
Oil Equivalents (MBoe) (2)				
Net proved reserves at December 31, 2012	1,662,108	101,060	47,530	1,810,698
Revisions of previous estimates	113,823	(3,892)	(941)	108,990
Purchases in place	3,241	—	—	3,241
Extensions, discoveries and other additions	383,324	13,245	2,396	398,965
Sales in place	(15,375)	—	—	(15,375)
Production	(157,955)	(22,049)	(7,972)	(187,976)
Net proved reserves at December 31, 2013	1,989,166	88,364	41,013	2,118,543
Revisions of previous estimates	97,782	2,245	541	100,568
Purchases in place	14,367	—	—	14,367
Extensions, discoveries and other additions	517,613	758	796	519,167
Sales in place	(14,661)	—	(21,602)	(36,263)
Production	(190,065)	(22,430)	(6,631)	(219,126)
Net proved reserves at December 31, 2014	2,414,202	68,937	14,117	2,497,256
Revisions of previous estimates	(470,401)	2,802	995	(466,604)
Purchases in place	56,215	—	—	56,215
Extensions, discoveries and other additions	241,513	3,682	736	245,931
Sales in place	(1,467)	—	(2,039)	(3,506)
Production	(187,701)	(21,578)	(1,896)	(211,175)
Net proved reserves at December 31, 2015	**2,052,361**	**53,843**	**11,913**	**2,118,117**

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

(2) Thousand barrels or thousand barrels of oil equivalent, as applicable; oil equivalents include crude oil and condensate, NGLs and natural gas. Oil equivalents are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas.

(3) Billion cubic feet.

During 2015, EOG added 246 million barrels of oil equivalent (MMBoe) of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin, the Rocky Mountain area and the Eagle Ford. Approximately 77% of the 2015 reserve additions were crude oil and condensate and NGLs, and 98% were in the United States. Sales in place of 4 MMBoe were primarily related to the disposition of certain producing natural gas assets in Canada, the Permian Basin and the Upper Gulf Coast. Negative revisions of previous estimates of 467 MMBoe for 2015 included a negative revision of 574 MMBoe primarily due to decreases in the average crude oil and natural gas prices used in the December 31, 2015, reserves estimation as compared to the prices used in the prior year estimate. The primary plays affected were the Uinta and Green River basins in the Rocky Mountain area, the Permian Basin and the Barnett Shale. Revisions other than price resulted primarily from improved recovery in the Eagle Ford.

During 2014, EOG added 519 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Eagle Ford, Permian Basin and the Rocky Mountain area. Approximately 79% of the 2014 reserve additions were crude oil and condensate and NGLs, and nearly 100% were in the United States. Sales in place of 36 MMBoe were primarily related to the disposition of certain producing natural gas assets in Canada, the Upper Gulf Coast and other producing basins in the United States. Positive revisions of previous estimates of 101 MMBoe for 2014 included a positive revision of 52 MMBoe primarily due to an increase in the average natural gas price used in the December 31, 2014 reserves estimation as compared to the price used in the prior year estimate. The primary plays affected were the Barnett Shale, the Uinta and Green River basins in the Rocky Mountain area and the Haynesville Shale play. Revisions other than price resulted primarily from improved recovery in the Eagle Ford and improved recoveries and reduced operating costs in the Permian Basin.

During 2013, EOG added 399 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Eagle Ford, Bakken, Permian Basin and Barnett Combo shale plays. Approximately 75% of the 2013 reserve additions were crude oil and condensate and NGLs, and over 96% were in the United States. Sales in place of 15 MMBoe were primarily related to the disposition of certain producing natural gas assets in South Texas, the Barnett Shale and the Permian Basin. Positive revisions of previous estimates of 109 MMBoe for 2013 included a positive revision of 61 MMBoe primarily due to an increase in the average natural gas price used in the December 31, 2013 reserves estimation as compared to the price used in the prior year estimate. The primary plays affected were the Barnett Shale, the Uinta and Green River basins in the Rocky Mountain area and the Haynesville Shale play. Revisions other than price resulted primarily from improved recovery in the Eagle Ford.

	United States	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2012	281,167	2,377	7,106	290,650
December 31, 2013	382,517	1,505	7,034	391,056
December 31, 2014	493,694	1,339	115	495,148
December 31, 2015	444,070	1,069	63	445,202
Natural Gas Liquids (MBbl)				
December 31, 2012	161,482	—	1,111	162,593
December 31, 2013	199,964	—	896	200,860
December 31, 2014	264,611	—	138	264,749
December 31, 2015	205,898	—	—	205,898
Natural Gas (Bcf)				
December 31, 2012	2,387.5	476.7	115.3	2,979.5
December 31, 2013	2,597.3	494.6	121.5	3,213.4
December 31, 2014	3,102.8	396.9	28.6	3,528.3
December 31, 2015	2,211.2	297.6	19.5	2,528.3
Oil Equivalents (MBoe)				
December 31, 2012	840,564	81,826	27,429	949,819
December 31, 2013	1,015,359	83,933	28,184	1,127,476
December 31, 2014	1,275,447	67,484	5,016	1,347,947
December 31, 2015	1,018,491	50,677	3,309	1,072,477
NET PROVED UNDEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2012	389,862	651	19,655	410,168
December 31, 2013	497,532	85	11,867	509,484
December 31, 2014	635,988	—	8,614	644,602
December 31, 2015	643,790	—	8,604	652,394
Natural Gas Liquids (MBbl)				
December 31, 2012	156,924	—	446	157,370
December 31, 2013	176,038	—	308	176,346
December 31, 2014	202,319	—	—	202,319
December 31, 2015	176,977	—	—	176,977
Natural Gas (Bcf)				
December 31, 2012	1,648.5	111.5	—	1,760.0
December 31, 2013	1,801.4	26.1	3.9	1,831.4
December 31, 2014	1,802.7	8.7	2.9	1,814.3
December 31, 2015	1,278.6	19.0	—	1,297.6
Oil Equivalents (MBoe)				
December 31, 2012	821,544	19,234	20,101	860,879
December 31, 2013	973,807	4,431	12,829	991,067
December 31, 2014	1,138,755	1,453	9,101	1,149,309
December 31, 2015	1,033,870	3,166	8,604	1,045,640

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

Net Proved Undeveloped Reserves. The following table presents the changes in EOG's total proved undeveloped reserves during 2015, 2014 and 2013 (in MBoe):

	2015	2014	2013
Balance at January 1	1,149,309	991,067	860,879
Extensions and Discoveries	205,152	403,713	291,345
Revisions	(241,973)	(79,630)	(855)
Acquisition of Reserves	54,458	4,239	—
Sale of Reserves	—	(10,176)	—
Conversion to Proved Developed Reserves	(121,306)	(159,904)	(160,302)
Balance at December 31	1,045,640	1,149,309	991,067

For the twelve-month period ended December 31, 2015, total PUDs decreased by 104 MMBoe to 1,046 MMBoe. EOG added approximately 52 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on pages F-30 and F-31 of this Annual Report on Form 10-K), EOG added 153 MMBoe. The PUD additions were primarily in the Permian Basin and, to a lesser extent, the Eagle Ford and the Rocky Mountain area, and 80% of the additions were crude oil and condensate and NGLs. During 2015, EOG drilled and transferred 121 MMBoe of PUDs to proved developed reserves at a total capital cost of $2,349 million. Revisions of PUDs totaled negative 242 MMBoe, primarily due to decreases in the average crude oil and natural gas prices used in the December 31, 2015, reserves estimation as compared to the prices used in the prior year estimate. During 2015, EOG did not sell any PUDs and acquired 54 MMBoe of PUDs.

For the twelve-month period ended December 31, 2014, total PUDs increased by 158 MMBoe to 1,149 MMBoe. EOG added approximately 50 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 354 MMBoe. The PUD additions were primarily in the Eagle Ford and Permian Basin, and 80% of the additions were crude oil and condensate and NGLs. During 2014, EOG drilled and transferred 160 MMBoe of PUDs to proved developed reserves at a total capital cost of $2,655 million. Revisions of PUDs totaled negative 80 MMBoe, primarily due to removal of certain natural gas PUDs. During 2014, EOG sold 10 MMBoe and acquired 4 MMBoe of PUDs.

For the twelve-month period ended December 31, 2013, total PUDs increased by 130 MMBoe to 991 MMBoe. EOG added approximately 28 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 263 MMBoe. The PUD additions were primarily in the Eagle Ford, Bakken and Permian Basin, and over 80% of the additions were crude oil and condensate and NGLs. During 2013, EOG drilled and transferred 160 MMBoe of PUDs to proved developed reserves at a total capital cost of $2,874 million. Revisions of PUDs totaled negative 1 MMBoe. During 2013, EOG did not sell any PUD reserves.

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's crude oil and natural gas producing activities at December 31, 2015 and 2014:

	2015	2014
Proved properties	$ 49,623,518	$ 45,169,101
Unproved properties	989,723	1,334,431
Total	50,613,241	46,503,532
Accumulated depreciation, depletion and amortization	(28,877,593)	(20,212,748)
Net capitalized costs	**$ 21,735,648**	**$ 26,290,784**

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in the Extractive Industries - Oil and Gas Topic of the Accounting Standards Codification (ASC).

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property.

Exploration costs include additions to exploratory wells, including those in progress, and exploration expenses.

Development costs include additions to production facilities and equipment and additions to development wells, including those in progress.

The following table sets forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2015, 2014 and 2013:

	United States	Trinidad	Other International (1)	Total
2015				
Acquisition Costs of Properties				
Unproved	$ 133,801	$ —	$ 56	$ 133,857
Proved	480,617	—	—	480,617
Subtotal	614,418	—	56	614,474
Exploration Costs	206,814	22,837	23,041	252,692
Development Costs (2)	3,847,813	102,715	110,589	4,061,117
Total	$ 4,669,045	$ 125,552	$ 133,686	$ 4,928,283
2014				
Acquisition Costs of Properties				
Unproved	$ 365,915	$ —	$ 4,499	$ 370,414
Proved	138,772	—	329	139,101
Subtotal	504,687	—	4,828	509,515
Exploration Costs	332,703	2,794	60,476	395,973
Development Costs (3)	6,638,192	89,555	271,534	6,999,281
Total	$ 7,475,582	$ 92,349	$ 336,838	$ 7,904,769
2013				
Acquisition Costs of Properties				
Unproved	$ 411,556	$ —	$ 2,565	$ 414,121
Proved	120,220	—	(6)	120,214
Subtotal	531,776	—	2,559	534,335
Exploration Costs	273,788	16,060	87,331	377,179
Development Costs (4)	5,573,260	124,231	388,886	6,086,377
Total	$ 6,378,824	$ 140,291	$ 478,776	$ 6,997,891

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations.
(2) Includes Asset Retirement Costs of $32 million, $15 million and $6 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(3) Includes Asset Retirement Costs of $149 million, $14 million and $33 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.
(4) Includes Asset Retirement Costs of $84 million and $50 million for the United States and Other International, respectively. Excludes other property, plant and equipment.

Results of Operations for Oil and Gas Producing Activities [1]. The following table sets forth results of operations for oil and gas producing activities for the years ended December 31, 2015, 2014 and 2013:

	United States	Trinidad	Other International [2]	Total
2015				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 5,962,753	$ 381,761	$ 58,744	$ 6,403,258
Other	47,464	(3)	448	47,909
Total	6,010,217	381,758	59,192	6,451,167
Exploration Costs	139,753	2,071	7,670	149,494
Dry Hole Costs	956	5,635	8,155	14,746
Transportation Costs	838,428	1,290	9,601	849,319
Production Costs	1,486,189	28,862	66,080	1,581,131
Impairments	6,402,908	—	210,638	6,613,546
Depreciation, Depletion and Amortization	3,017,386	154,588	18,469	3,190,443
Income (Loss) Before Income Taxes	(5,875,403)	189,312	(261,421)	(5,947,512)
Income Tax Provision (Benefit)	(2,128,183)	43,739	(2,111)	(2,086,555)
Results of Operations	$ (3,747,220)	$ 145,573	$ (259,310)	$ (3,860,957)
2014				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$11,771,777	$ 512,675	$ 308,465	$12,592,917
Other	49,950	37	4,257	54,244
Total	11,821,727	512,712	312,722	12,647,161
Exploration Costs	162,434	2,185	19,769	184,388
Dry Hole Costs	25,408	—	23,082	48,490
Transportation Costs	957,522	617	14,037	972,176
Production Costs	1,940,074	38,301	171,652	2,150,027
Impairments	331,792	—	411,783	743,575
Depreciation, Depletion and Amortization	3,571,313	188,250	122,157	3,881,720
Income (Loss) Before Income Taxes	4,833,184	283,359	(449,758)	4,666,785
Income Tax Provision	1,722,914	74,588	23,602	1,821,104
Results of Operations	$ 3,110,270	$ 208,771	$ (473,360)	$ 2,845,681
2013				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 9,897,701	$ 517,482	$ 340,463	$10,755,646
Other	51,713	24	4,770	56,507
Total	9,949,414	517,506	345,233	10,812,153
Exploration Costs	141,286	2,345	17,715	161,346
Dry Hole Costs	14,276	4,478	55,901	74,655
Transportation Costs	841,567	659	10,818	853,044
Production Costs	1,494,791	43,279	168,152	1,706,222
Impairments	178,718	14,274	93,949	286,941
Depreciation, Depletion and Amortization	3,122,858	181,637	193,515	3,498,010
Income (Loss) Before Income Taxes	4,155,918	270,834	(194,817)	4,231,935
Income Tax Provision (Benefit)	1,486,445	103,313	(99,226)	1,490,532
Results of Operations	$ 2,669,473	$ 167,521	$ (95,591)	$ 2,741,403

(1) Excludes gains or losses on the mark-to-market of financial commodity derivative contracts, gains or losses on sales of reserves and related assets, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2015.

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

The following table sets forth production costs per barrel of oil equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2015, 2014 and 2013:

	United States	Trinidad	Other International [(1)]	Composite
Year Ended December 31, 2015	$ 5.81	$ 1.29	$ 33.78	$ 5.85
Year Ended December 31, 2014	$ 6.44	$ 1.34	$ 24.60	$ 6.46
Year Ended December 31, 2013	$ 5.78	$ 1.36	$ 20.40	$ 5.88

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by the Extractive Industries - Oil and Gas Topic of the ASC and based on crude oil, NGL and natural gas reserves and production volumes estimated by the Engineering and Acquisitions Department of EOG. The estimates were based on a 12-month average for commodity prices for the years 2015, 2014 and 2013. The following information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

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

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

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's oil and gas reserves for the years ended December 31, 2015, 2014 and 2013:

	United States	Trinidad	Other International [1]	Total
2015				
Future cash inflows [2]	$ 67,242,928	$ 954,779	$ 522,941	$ 68,720,648
Future production costs	(31,707,743)	(183,607)	(169,505)	(32,060,855)
Future development costs	(15,579,923)	(140,541)	(65,347)	(15,785,811)
Future income taxes	(4,400,542)	(215,659)	—	(4,616,201)
Future net cash flows	15,554,720	414,972	288,089	16,257,781
Discount to present value at 10% annual rate	(6,589,253)	(33,848)	(13,284)	(6,636,385)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 8,965,467	$ 381,124	$ 274,805	$ 9,621,396
2014				
Future cash inflows [3]	$144,355,692	$ 1,615,280	$ 979,249	$146,950,221
Future production costs	(51,112,604)	(277,844)	(242,845)	(51,633,293)
Future development costs	(20,270,439)	(84,576)	(139,750)	(20,494,765)
Future income taxes	(22,725,618)	(460,096)	—	(23,185,714)
Future net cash flows	50,247,031	792,764	596,654	51,636,449
Discount to present value at 10% annual rate	(23,542,990)	(110,228)	(59,813)	(23,713,031)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 26,704,041	$ 682,536	$ 536,841	$ 27,923,418
2013				
Future cash inflows [4]	$119,644,713	$ 2,082,195	$ 2,272,591	$123,999,499
Future production costs	(49,099,393)	(315,483)	(751,612)	(50,166,488)
Future development costs	(17,753,860)	(112,050)	(683,441)	(18,549,351)
Future income taxes	(15,763,089)	(603,786)	(49,512)	(16,416,387)
Future net cash flows	37,028,371	1,050,876	788,026	38,867,273
Discount to present value at 10% annual rate	(17,451,470)	(174,236)	91,865	(17,533,841)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 19,576,901	$ 876,640	$ 879,891	$ 21,333,432

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

(2) Estimated crude oil prices used to calculate 2015 future cash inflows for the United States, Trinidad and Other International were $49.58, $38.83 and $47.76, respectively. Estimated NGL price used to calculate 2015 future cash inflows for the United States was $15.17. Estimated natural gas prices used to calculate 2015 future cash inflows for the United States, Trinidad and Other International were $2.15, $2.88 and $5.60, respectively.

(3) Estimated crude oil prices used to calculate 2014 future cash inflows for the United States, Trinidad and Other International were $97.51, $80.60 and $94.09, respectively. Estimated NGL prices used to calculate 2014 future cash inflows for the United States and Other International were $34.29 and $27.03, respectively. Estimated natural gas prices used to calculate 2014 future cash inflows for the United States, Trinidad and Other International were $3.71, $3.71 and $5.14, respectively.

(4) Estimated crude oil prices used to calculate 2013 future cash inflows for the United States, Trinidad and Other International were $105.91, $94.30 and $98.85, respectively. Estimated NGL prices used to calculate 2013 future cash inflows for the United States and Other International were $29.42 and $40.88, respectively. Estimated natural gas prices used to calculate 2013 future cash inflows for the United States, Trinidad and Other International were $3.50, $3.71 and $3.45, respectively.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2015:

	United States	Trinidad	Other International [1]	Total
December 31, 2012	$ 15,181,334	$ 961,070	$ 773,068	$ 16,915,472
Sales and transfers of oil and gas produced, net of production costs	(7,561,343)	(473,544)	(161,493)	(8,196,380)
Net changes in prices and production costs	1,734,058	(12,050)	(464,155)	1,257,853
Extensions, discoveries, additions and improved recovery, net of related costs	5,449,531	—	33,901	5,483,432
Development costs incurred	2,792,400	67,100	96,400	2,955,900
Revisions of estimated development cost	892,803	(3,539)	101,132	990,396
Revisions of previous quantity estimates	1,887,062	(60,419)	(32,445)	1,794,198
Accretion of discount	1,895,503	147,099	91,127	2,133,729
Net change in income taxes	(2,772,267)	56,373	137,644	(2,578,250)
Purchases of reserves in place	66,359	—	—	66,359
Sales of reserves in place	(140,652)	—	—	(140,652)
Changes in timing and other	152,113	194,550	304,712	651,375
December 31, 2013	19,576,901	876,640	879,891	21,333,432
Sales and transfers of oil and gas produced, net of production costs	(8,874,180)	(473,757)	(122,777)	(9,470,714)
Net changes in prices and production costs	1,481,668	(12,079)	(206,412)	1,263,177
Extensions, discoveries, additions and improved recovery, net of related costs	8,074,550	3,113	6,189	8,083,852
Development costs incurred	2,818,800	12,800	3,500	2,835,100
Revisions of estimated development cost	1,696,916	9,981	95,838	1,802,735
Revisions of previous quantity estimates	1,741,918	35,001	35,613	1,812,532
Accretion of discount	2,612,286	133,019	88,045	2,833,350
Net change in income taxes	(3,743,300)	91,438	562	(3,651,300)
Purchases of reserves in place	317,785	—	—	317,785
Sales of reserves in place	(189,808)	—	(289,071)	(478,879)
Changes in timing and other	1,190,505	6,380	45,463	1,242,348
December 31, 2014	26,704,041	682,536	536,841	27,923,418
Sales and transfers of oil and gas produced, net of production costs	(3,685,600)	(351,606)	16,489	(4,020,717)
Net changes in prices and production costs	(29,993,699)	(370,503)	(305,148)	(30,669,350)
Extensions, discoveries, additions and improved recovery, net of related costs	1,028,410	47,613	19,875	1,095,898
Development costs incurred	2,135,800	500	1,400	2,137,700
Revisions of estimated development cost	4,087,093	(34,647)	26,935	4,079,381
Revisions of previous quantity estimates	(4,084,572)	33,285	(587)	(4,051,874)
Accretion of discount	3,699,330	104,464	53,685	3,857,479
Net change in income taxes	9,550,847	177,576	—	9,728,423
Purchases of reserves in place	123,542	—	—	123,542
Sales of reserves in place	(23,424)	—	(13,664)	(37,088)
Changes in timing and other	(576,301)	91,906	(61,021)	(545,416)
December 31, 2015	**$ 8,965,467**	**$ 381,124**	**$ 274,805**	**$ 9,621,396**

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

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

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

Quarter Ended	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2015				
Net Operating Revenues	$ 2,318,538	$ 2,469,701	$ 2,172,428	$ 1,796,761
Operating Income (Loss)	$ (172,995)	$ 39,626	$ (6,222,957)	$ (329,753)
Income (Loss) Before Income Taxes	$ (236,331)	$ (11,478)	$ (6,274,921)	$ (398,826)
Income Tax Benefit	(66,583)	(16,746)	(2,199,182)	(114,530)
Net Income (Loss)	$ (169,748)	$ 5,268	$ (4,075,739)	$ (284,296)
Net Income (Loss) Per Share [(1)]				
Basic	$ (0.31)	$ 0.01	$ (7.47)	$ (0.52)
Diluted	$ (0.31)	$ 0.01	$ (7.47)	$ (0.52)
Average Number of Common Shares				
Basic	544,998	545,504	545,920	546,432
Diluted	544,998	549,683	545,920	546,432
2014				
Net Operating Revenues	$ 4,083,671	$ 4,187,556	$ 5,118,616	$ 4,645,497
Operating Income	$ 1,084,279	$ 1,144,730	$ 1,786,162	$ 1,226,652
Income Before Income Taxes	$ 1,030,789	$ 1,100,813	$ 1,715,120	$ 1,148,593
Income Tax Provision	369,861	394,460	611,502	704,005
Net Income	$ 660,928	$ 706,353	$ 1,103,618	$ 444,588
Net Income Per Share [(1)]				
Basic	$ 1.22	$ 1.30	$ 2.03	$ 0.82
Diluted	$ 1.21	$ 1.29	$ 2.01	$ 0.81
Average Number of Common Shares				
Basic	542,278	543,099	543,984	544,579
Diluted	548,071	548,676	549,518	549,153

(1) The sum of quarterly net income (loss) per share may not agree with total year net income (loss) per share as each quarterly computation is based on the weighted average of common shares outstanding.

EXHIBITS

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

Exhibit Number		Description
3.1(a)	-	Restated Certificate of Incorporation, dated September 3, 1987 (Exhibit 3.1(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
3.1(b)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 5, 1993 (Exhibit 4.1(b) to EOG's Registration Statement on Form S-8, SEC File No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 14, 1994 (Exhibit 4.1(c) to EOG's Registration Statement on Form S-8, SEC File No. 33-58103, filed March 15, 1995).
3.1(d)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to EOG's Registration Statement on Form S-3, SEC File No. 333-09919, filed August 9, 1996).
3.1(e)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to EOG's Registration Statement on Form S-3, SEC File No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger Merging EOG Resources, Inc. into Enron Oil & Gas Company, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to EOG's Registration Statement on Form 8-A, SEC File No. 001-09743, filed February 18, 2000).
3.1(h)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 13, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 13, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004) (SEC File No. 001-09743).
3.1(k)	-	Amended Certificate of Designations of Series E Junior Participating Preferred Stock, dated March 7, 2005 (Exhibit 3.1(m) to EOG's Annual Report on Form 10-K for the year ended December 31, 2007) (SEC File No. 001-09743).
3.1(l)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005) (SEC File No. 001-09743).
3.1(m)	-	Certificate of Elimination of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated March 6, 2008 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed March 6, 2008) (SEC File No. 001-09743).
3.2	-	Bylaws, dated August 23, 1989, as amended and restated effective as of September 22, 2015 (Exhibit 3.1 to EOG’s Current Report on Form 8-K, filed September 28, 2015).
4.1	-	Specimen of Certificate evidencing EOG's Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
4.2	-	Indenture, dated as of September 1, 1991, between Enron Oil & Gas Company (predecessor to EOG) and The Bank of New York Mellon Trust Company, N.A. (as successor in interest to JPMorgan Chase Bank, N.A. (formerly, Texas Commerce Bank National Association)), as Trustee (Exhibit 4(a) to EOG's Registration Statement on Form S-3, SEC File No. 33-42640, filed September 6, 1991).
4.3(a)	-	Officers' Certificate Establishing 6.125% Senior Notes due 2013 and 6.875% Senior Notes due 2018 of EOG, dated September 30, 2008 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 30, 2008) (SEC File No. 001-09743).

Exhibit Number		Description
4.3(b)	-	Form of Global Note with respect to the 6.875% Senior Notes due 2018 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed September 30, 2008) (SEC File No. 001-09743).
4.4(a)	-	Officers' Certificate Establishing 5.875% Senior Notes due 2017 of EOG, dated September 10, 2007 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 10, 2007) (SEC File No. 001-09743).
4.4(b)	-	Form of Global Note with respect to the 5.875% Senior Notes due 2017 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 10, 2007) (SEC File No. 001-09743).
#4.5(a)	-	Certificate, dated April 3, 1998, of the Senior Vice President and Chief Financial Officer of Enron Oil & Gas Company (predecessor to EOG) establishing the terms of the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company.
#4.5(b)	-	Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
4.6	-	Indenture, dated as of May 18, 2009, between EOG and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.9 to EOG's Registration Statement on Form S-3, SEC File No. 333-159301, filed May 18, 2009).
4.7(a)	-	Officers' Certificate Establishing 5.625% Senior Notes due 2019 of EOG, dated May 21, 2009 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 21, 2009) (SEC File No. 001-09743).
4.7(b)	-	Form of Global Note with respect to the 5.625% Senior Notes due 2019 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 21, 2009) (SEC File No. 001-09743).
4.8(a)	-	Officers' Certificate Establishing 2.95% Senior Notes due 2015 and 4.40% Senior Notes due 2020 of EOG, dated May 20, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 26, 2010) (SEC File No. 001-09743).
4.8(b)	-	Form of Global Note with respect to the 4.40% Senior Notes due 2020 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed May 26, 2010) (SEC File No. 001-09743).
4.9(a)	-	Officers' Certificate Establishing 2.500% Senior Notes due 2016, 4.100% Senior Notes due 2021 and Floating Rate Senior Notes due 2014 of EOG, dated November 23, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed November 24, 2010) (SEC File No. 001-09743).
4.9(b)	-	Form of Global Note with respect to the 2.500% Senior Notes due 2016 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed November 24, 2010) (SEC File No. 001-09743).
4.9(c)	-	Form of Global Note with respect to the 4.100% Senior Notes due 2021 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed November 24, 2010) (SEC File No. 001-09743).
4.10(a)	-	Officers' Certificate Establishing 2.625% Senior Notes due 2023 of EOG, dated September 10, 2012 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 11, 2012).
4.10(b)	-	Form of Global Note with respect to the 2.625% Senior Notes due 2023 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 11, 2012).
4.11(a)	-	Officers' Certificate Establishing 2.45% Senior Notes due 2020 of EOG, dated March 21, 2014 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed March 25, 2014).
4.11(b)	-	Form of Global Note with respect to the 2.45% Senior Notes due 2020 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed March 25, 2014).
4.12(a)	-	Officers' Certificate Establishing 3.15% Senior Notes due 2025 and 3.90% Senior Notes due 2035 of EOG, dated March 17, 2015 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed March 19, 2015).
4.12(b)	-	Form of Global Note with respect to the 3.15% Senior Notes due 2025 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed March 19, 2015).
4.12(c)	-	Form of Global Note with respect to the 3.90% Senior Notes due 2035 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed March 19, 2015).
4.13(a)	-	Officers' Certificate Establishing 4.15% Senior Notes due 2026 and 5.10% Senior Notes due 2036 of EOG, dated January 14, 2016 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed January 15, 2016).
4.13(b)	-	Form of Global Note with respect to the 4.15% Senior Notes due 2026 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed January 15, 2016).

Exhibit Number		Description
4.13(c)	-	Form of Global Note with respect to the 5.10% Senior Notes due 2036 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed January 15, 2016).
10.1(a)+	-	EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 8, 2008 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(b)+	-	First Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 4, 2008 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008) (SEC File No. 001-09743).
10.1(c)+	-	Second Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of January 1, 2010 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010) (SEC File No. 001-09743).
10.1(d)+	-	Third Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 26, 2012 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.1(e)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made prior to February 23, 2011) (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(f)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made on or after February 23, 2011) (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.1(g)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made prior to February 23, 2011) (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(h)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (effective for grants made on or after February 23, 2011) (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.1(i)	-	Form of Nonemployee Director Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(j)+	-	Form of Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(k)+	-	Form of Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.6 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(l)	-	Form of Nonemployee Director Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.7 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(m)	-	Form of Nonemployee Director Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
10.1(n)+	-	Form of Performance Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed October 1, 2012).
10.1(o)+	-	Form of Performance Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed October 1, 2012).
10.2(a)+	-	Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 2, 2013 (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(b)+	-	Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.5 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).

Exhibit Number		Description
10.2(c)+	-	Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.6 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(d)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.7 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(e)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.8 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(f)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 22, 2014) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014).
10.2(g)+	-	Form of Performance Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.9 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(h)	-	Form of Non-Employee Director Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.10 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(i)	-	Form of Non-Employee Director Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.11 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.3(a)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Plan Document, effective as of December 16, 2008 (Exhibit 10.2(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(b)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Adoption Agreement, originally dated as of December 16, 2008 (and as amended through February 24, 2012 (including an amendment to Item 7 thereof, effective January 1, 2012, with respect to the deferral of restricted stock units)) (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2011) (originally filed as Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(c)+	-	First Amendment to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of January 1, 2013 (Exhibit 10.8 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).
10.3(d)+	-	Amended and Restated 1996 Deferral Plan (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-84014, filed March 8, 2002).
10.3(e)+	-	First Amendment to Amended and Restated 1996 Deferral Plan, effective as of September 10, 2002 (Exhibit 10.9(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2002) (SEC File No. 001-09743).
10.4(a)	-	EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, as amended and restated effective May 7, 2002 (Exhibit A to EOG's Proxy Statement, filed March 28, 2002, with respect to EOG's 2002 Annual Meeting of Stockholders) (SEC File No. 001-09743).
10.4(b)	-	First Amendment to EOG Resources, Inc. 1993 Nonemployee Directors Stock Option Plan, dated effective as of December 30, 2005 (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2005) (SEC File No. 001-09743).
10.5(a)+	-	Change of Control Agreement between EOG and William R. Thomas, effective as of January 12, 2011 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
10.5(b)+	-	First Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 13, 2011 (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed September 13, 2011).
10.5(c)+	-	Second Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 4, 2013 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).

Exhibit Number		Description
10.6(a)+	-	Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.9 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.6(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of April 30, 2009 (Exhibit 10.3(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.6(c)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 13, 2011 (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed September 13, 2011).
10.6(d)+	-	Third Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 4, 2013 (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).
10.7(a)+	-	Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.7(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of April 30, 2009 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.7(c)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of September 13, 2011 (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 13, 2011).
10.8(a)+	-	Change of Control Agreement by and between EOG and Michael P. Donaldson, effective as of May 3, 2012 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
10.8(b)+	-	First Amendment to Change of Control Agreement between EOG and Michael P. Donaldson, effective as of September 4, 2013 (Exhibit 10.7 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).
10.9(a)+	-	Change of Control Agreement by and between EOG and Lloyd W. Helms, effective as of June 27, 2013 (Exhibit 10.9 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.9(b)+	-	First Amendment to Change of Control Agreement between EOG and Lloyd W. Helms, Jr., effective as of September 4, 2013 (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).
10.10+	-	Change of Control Agreement by and between EOG and David W. Trice, effective as of September 4, 2013 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013).
10.11(a)+	-	EOG Resources, Inc. Change of Control Severance Plan, as amended and restated effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.11(b)+	-	First Amendment to the EOG Resources, Inc. Change of Control Severance Plan, effective as of April 30, 2009 (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.12+	-	EOG Resources, Inc. Amended and Restated Executive Officer Annual Bonus Plan (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010) (SEC File No. 001-09743).
10.13(a)+	-	EOG Resources, Inc. Employee Stock Purchase Plan (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-62256, filed June 4, 2001).
10.13(b)+	-	Amendment to EOG Resources, Inc. Employee Stock Purchase Plan, dated effective as of January 1, 2010 (Exhibit 4.3(b) to EOG's Registration Statement on Form S-8, SEC File No. 333-166518, filed May 4, 2010).
10.14	-	Revolving Credit Agreement, dated as of July 21, 2015, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed July 24, 2015).

Exhibit Number		Description
* 12	-	Computation of Ratio of Earnings to Fixed Charges.
* 21	-	Subsidiaries of EOG, as of December 31, 2015.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Opinion of DeGolyer and MacNaughton dated February 1, 2016.
* 23.3	-	Consent of Deloitte & Touche LLP.
* 24	-	Powers of Attorney.
* 31.1	-	Section 302 Certification of Annual Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Annual Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.
* 95	-	Mine Safety Disclosure Exhibit.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income for Each of the Three Years in the Period Ended December 31, 2015, (ii) the Consolidated Balance Sheets - December 31, 2015 and 2014, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2015, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2015 and (v) the Notes to Consolidated Financial Statements.

+ Management contract, compensatory plan or arrangement

SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: February 25, 2016

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

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities with EOG Resources, Inc. indicated and on the 25th day of February, 2016.

Signature	Title
/s/ WILLIAM R. THOMAS (William R. Thomas)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ ANN D. JANSSEN (Ann D. Janssen)	Vice President, Accounting (Principal Accounting Officer)
* (Janet F. Clark)	Director
* (Charles R. Crisp)	Director
* (James C. Day)	Director
* (H. Leighton Steward)	Director
* (Donald F. Textor)	Director
* (Frank G. Wisner)	Director

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

EOG RESOURCES, INC. AND SUBSIDIARIES
EXHIBITS TO FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015
INDEX OF EXHIBITS

Exhibit Number		Description
* 12	-	Computation of Ratio of Earnings to Fixed Charges.
* 21	-	Subsidiaries of EOG, as of December 31, 2015.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Opinion of DeGolyer and MacNaughton dated February 1, 2016.
* 23.3	-	Consent of Deloitte & Touche LLP.
* 24	-	Powers of Attorney.
* 31.1	-	Section 302 Certification of Annual Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Annual Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.
* 95	-	Mine Safety Disclosure Exhibit.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income for Each of the Three Years in the Period Ended December 31, 2015, (ii) the Consolidated Balance Sheets - December 31, 2015 and 2014, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2015, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2015 and (v) the Notes to Consolidated Financial Statements.