APACHE CORP
Form 10-K
February 27, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

or

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

For the transition period from to

Commission file number 1-4300

APACHE CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**41-0747868**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400

(Address of principal executive offices)

Registrant s telephone number, including area code (713) 296-6000

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	**New York Stock Exchange, Chicago Stock Exchange and NASDAQ National Market**
Apache Finance Canada Corporation 7.75% Notes Due 2029	**New York Stock Exchange**
Irrevocably and Unconditionally	
Guaranteed by Apache Corporation	

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.625 par value

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

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

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 x 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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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 x	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 x

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2014	$ 38,470,137,875

Number of shares of registrant s common stock outstanding as of January 31, 2015	376,823,368

Documents Incorporated By Reference

Portions of registrant s proxy statement relating to registrant s 2015 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

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DESCRIPTION

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

3-D means three-dimensional.

4-D means four-dimensional.

b/d means barrels of oil or natural gas liquids per day.

bbl or bbls means barrel or barrels of oil or natural gas liquids.

bcf means billion cubic feet of natural gas.

boe means barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.

boe/d means boe per day.

Btu means a British thermal unit, a measure of heating value.

LIBOR means London Interbank Offered Rate.

LNG means liquefied natural gas.

Mb/d means Mbbls per day.

Mbbls means thousand barrels of oil or natural gas liquids.

Mboe means thousand boe.

Mboe/d means Mboe per day.

Mcf means thousand cubic feet of natural gas.

Mcf/d means Mcf per day.

MMbbls means million barrels of oil or natural gas liquids.

MMboe means million boe.

MMBtu means million Btu.

MMBtu/d means MMBtu per day.

MMcf means million cubic feet of natural gas.

MMcf/d means MMcf per day.

NGL or NGLs means natural gas liquids, which are expressed in barrels.

NYMEX means New York Mercantile Exchange.

oil includes crude oil and condensate.

PUD means proved undeveloped.

SEC means United States Securities and Exchange Commission.

Tcf means trillion cubic feet of natural gas.

U.K. means United Kingdom.

U.S. means United States.

With respect to information relating to our working interest in wells or acreage, net oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

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PART I

ITEMS 1 AND 2. *BUSINESS AND PROPERTIES*

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See the risk factors set forth in Item 1A of this Form 10-K and Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk Forward-Looking Statements and Risk of this Form 10-K.

General

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. We currently have exploration and production interests in five countries: the U.S., Canada, Egypt, Australia, and the U.K. North Sea (North Sea). Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities. We treat all operations as one line of business.

Our common stock, par value $0.625 per share, has been listed on the New York Stock Exchange (NYSE) since 1969, on the Chicago Stock Exchange (CHX) since 1960, and on the NASDAQ National Market (NASDAQ) since 2004. On June 10 and 11, 2014, we filed certifications of our compliance with the listing standards of the NYSE and the NASDAQ, including our principal executive officer s certification of compliance with the NYSE standards. Through our website, www.apachecorp.com, you can access, free of charge, electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance (including our Code of Business Conduct and Governance Principles), and documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. Included in our annual and quarterly reports are the certifications of our principal executive officer and our principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. You may also request printed copies of our committee charters or other governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Our reports filed with the SEC are made available to read and copy at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov. From time to time, we also post announcements, updates, and investor information on our website in addition to copies of all recent press releases. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Properties to which we refer in this document may be held by subsidiaries of Apache Corporation. References to Apache or the Company include Apache Corporation and its consolidated subsidiaries unless otherwise specifically stated.

Business Strategy

Apache s mission is to grow a profitable exploration and production company in a safe and environmentally responsible manner for the long-term benefit of our shareholders. Apache s long-term perspective has many dimensions, which are centered on the following core strategic components:

- rigorous portfolio management
- conservative capital structure

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rate of return focus

continuous improvement in operating and capital efficiency

Throughout the cycles of our industry, this strategy has underpinned our ability to deliver long-term production and reserve growth and achieve competitive returns on invested capital for the benefit of our shareholders. We have increased reserves 23 out of the last 29 years and production 32 out of the past 36 years, a testament to our consistency over the long-term.

We continuously review and optimize our portfolio of assets in response to changing industry and economic conditions. Over the last several years, Apache has taken action to monetize certain nonstrategic international assets, and enhance and streamline our North American onshore portfolio through a series of divestitures of noncore assets. These include:

LNG Projects On December 15, 2014, Apache subsidiaries announced the sale of the Kitimat LNG and Wheatstone LNG projects, along with accompanying upstream oil and gas reserves to Woodside Petroleum Limited for cash consideration of $2.75 billion plus recovery of Apache s net expenditures in the Wheatstone and Kitimat projects between June 30, 2014 and closing.

Nonstrategic Assets in the Anadarko Basin and in Southern Louisiana On December 31, 2014, Apache completed the sale of certain Anadarko basin and southern Louisiana oil and gas assets for approximately $1.3 billion in two separate transactions. In the Anadarko basin, Apache sold approximately 115,000 net acres in Wheeler County, Texas, and western Oklahoma. In southern Louisiana, the Company sold working interests in approximately 90,000 net acres.

Certain Gulf of Mexico Deepwater Assets On June 30, 2014, Apache completed the sale of non-operated interests in the Lucius and Heidelberg development projects and 11 primary term deepwater exploration blocks in the Gulf of Mexico for $1.4 billion. The effective date of the transaction was May 1, 2014.

Nonstrategic Canadian Assets On April 30, 2014, Apache completed the sale of primarily dry gas producing hydrocarbon assets in the Deep Basin area of western Alberta and British Columbia, Canada, for $374 million. The assets comprise 328,400 net acres in the Ojay, Noel, and Wapiti areas. Apache retained 100 percent of its working interest in horizons below the Cretaceous in the Wapiti area, including rights to the liquids-rich Montney and other deeper horizons. The effective date of the transaction was January 1, 2014.

Argentina Operations On March 12, 2014, Apache s subsidiaries completed the sale of all of the Company s operations in Argentina to YPF Sociedad Anónima for $800 million (subject to customary closing adjustments) plus the assumption of $52 million of bank debt as of June 30, 2013.

Egypt Sinopec Partnership On November 14, 2013, Apache announced the completion of the sale of a one-third minority participation in its Egypt oil and gas business to a subsidiary of Sinopec International

Petroleum Exploration and Production Corporation (Sinopec). Apache received cash consideration of $2.95 billion. This noncontrolling interest is recorded separately in the Company s financial statements.

Gulf of Mexico Shelf Operations On September 30, 2013, Apache completed the sale of its Gulf of Mexico Shelf operations and properties to Fieldwood Energy LLC (Fieldwood), an affiliate of Riverstone Holdings. Under the terms of the agreement, Apache received cash consideration of $3.7 billion, and Fieldwood assumed $1.5 billion of discounted asset abandonment liabilities. Additionally, Apache retained 50 percent of its ownership interest in both exploration blocks and in horizons below production in developed blocks, and access to existing infrastructure.

We intend to focus our growth initiatives on our North American onshore portfolio. Our Egypt and the North Sea regions provide a strong complement to our North American production and cash flow by generating

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steady and attractive rates of return and excess cash flow. This is particularly true in the context of the recent oil price downturn, as the cash flows from both Egypt and the North Sea are less sensitive to falling oil prices than our North American assets. We currently have no intention to exit Egypt or the North Sea. Our non-LNG Australian assets offer a dynamic exploration opportunity; however, we continue to evaluate this area for potential monetization.

While we cannot predict the length or depth of the current oil price correction, or the timing and extent of a potential price rebound, we have moved quickly and decisively regarding what we can control: the timing and levels of capital spending and our cost structure. Specifically, during the third quarter of 2014 we were operating 91 rigs onshore in North America, and by the end of February 2015, our rig count was reduced to 27 rigs. We also reduced the number of completion crews and will delay completing some of our wells in backlog until the associated service costs align with the current commodity price environment. In addition to well cost initiatives, we have taken steps to reduce both lease operating and general and administrative expenses and will continue to take proactive measures to reduce them further. We intend to manage the current downturn as we have other downturns throughout our 60-year history. Apache has proven its ability to capitalize on historical cycles of low commodity prices by focusing on a strong balance sheet, cost discipline, operating efficiency, adding to its extensive inventory of drilling locations, and ensuring we are prepared to take advantage of potential opportunities that arise as a result of low commodity prices, such as the availability of key acreage at attractive prices.

For a more in-depth discussion of our growth strategy, 2014 results, and the Company s capital resources and liquidity, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Geographic Area Overviews

During 2014, we had exploration and production interests in six countries: the U.S., Canada, Egypt, Australia, the U.K. North Sea, and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities. In March 2014, the Company completed the sale of all of its operations in Argentina. Results of operations and cash flows for Argentina operations are reflected as discontinued operations in the Company s financial statements and are not included in the following table.

The following table sets out a brief comparative summary of certain key 2014 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	Production (In MMboe)	Percentage of Total Production	Production Revenue (In millions)	Year-End Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	Gross Wells Drilled	Gross Productive Wells Drilled
United States	106.2	45%	$ 5,744	1,234	52%	1,118	1,095
Canada	28.3	12	1,092	414	17	106	102
Total North America	134.5	57	6,836	1,648	69	1,224	1,197
Egypt[(1)]	54.9	23	3,539	280	12	220	180

Australia	20.5	9	1,058	323	13	12	10
North Sea	26.1	11	2,316	145	6	22	20
Total International	101.5	43	6,913	748	31	254	210
Total	236.0	100%	$ 13,749	2,396	100%	1,478	1,407

(1) Includes production volumes, revenues, and reserves attributable to a noncontrolling interest in Egypt.

North America

Apache s North American onshore and offshore asset base primarily comprises operations in the Permian Basin, the Anadarko basin in western Oklahoma and the Texas Panhandle, Gulf Coast areas of the U.S., and in Western Canada. We also have leasehold acreage holdings in the Cook Inlet of Alaska and other areas where we are pursuing exploration opportunities. Over the past several years, the Company acquired significant acreage positions in many attractive basins and plays across North America. This portfolio expansion phase shifted during 2013 and 2014 when we completed strategic divestitures to rebalance our portfolio to an asset mix that we believe will drive more predictable growth and deliver increased value to our shareholders. As part of this effort, Apache s drilling activity has focused on our North America onshore assets, which delivered liquids growth of 19 percent during 2014 excluding the impacts of divestitures. Our North American asset base has a significant inventory of drilling opportunities and base production that provides a foundation for the Company to be flexible in its approach to capital allocation. This flexibility is critical to managing cash flows given volatile commodity prices for crude oil and natural gas.

With the recent decline in oil prices and reduction in our expected cash flow, we have initially set our 2015 capital budget for North America at $2.1 billion to $2.3 billion. This reflects an approximately 65 percent decline from the prior year. This budget covers planned expenditures for drilling, completions, recompletion projects, equipment upgrades, expansion of existing facilities and equipment, plugging and abandonment, seismic studies, and leasing additional acreage.

North America Onshore

Overview We have access to significant liquid hydrocarbons across our 12 million gross acres onshore in the U.S. and Canada, approximately 60 percent of which is undeveloped. Approximately 55 percent of Apache s worldwide equivalent 2014 production and 68 percent of our estimated year-end proved reserves were in our U.S. and Canada onshore regions. To manage our development efforts across broad acreage positions within North America, our onshore assets are divided into four regions: Permian, Gulf Coast, Central, and Canada.

Permian Region Our Permian region controls over 3.2 million gross acres with exposure to numerous plays across the Permian Basin. Apache is one of the largest operators in the Permian Basin, with more than 14,500 producing wells in 155 fields, including 47 waterfloods and seven CO_2 floods. Total region production for 2014 was up 25 percent sequentially as a result of an active drilling program where we ran an average of 40 rigs during the year. Production in the region has increased for 16 consecutive quarters. During the year, we drilled or participated in drilling 728 wells, of which 244 were horizontal. The Permian region s year-end 2014 estimated proved reserves were 970 MMboe, representing 7 percent growth over year-end 2013.

Over the past several years, the region has been testing numerous formations and building a large inventory of horizontal opportunities in several plays across our acreage position. In 2014, production growth was driven by Wolfcamp wells in the Barnhart area and in the Southern Midland Basin, the Bone Springs development program in the Delaware basin, and Yeso drilling on the Northwest shelf.

We continue to balance large development programs with exploration activity in several new areas. Given its acreage holdings, recent seismic data acquisitions and continued exploration efforts, the region has built a deep portfolio of drilling inventory and opportunities to sustain our activity for many years.

Gulf Coast Region Apache s Gulf Coast region is known for its proven onshore and near-shore basins of Texas and Louisiana where it has a significant acreage position of approximately 1.2 million gross acres, including approximately 285,000 mineral fee acres. Total region production in 2014 was 30 Mboe/d, of which 50 percent was oil and natural gas liquids.

During the year, the region continued to delineate its East Texas Eagle Ford play, primarily in Brazos and Burleson counties, with consistently strong results. As our drilling program has continued to advance, we acquired over $600 million of additional Eagle Ford acreage in surrounding areas in 2014. The region drilled or participated in drilling 77 wells in 2014.

In December 2014, Apache sold its working interest in approximately 90,000 net acres in southern Louisiana and Mississippi for $560 million. The effective date of the transaction is October 1, 2014. Apache s Gulf Coast regional production for 2015 will be almost entirely attributable to the East Texas Eagle Ford play.

Central Region The Central region controls 2.2 million gross acres and includes 3,150 producing wells primarily in western Oklahoma and the Texas Panhandle. The majority of our drilling activity during 2014 was focused in legacy Anadarko basin formations such as the Granite Wash, Marmaton, Cottage Grove, and Cleveland. Total region production in 2014 was 91 Mboe/d, of which 52 percent was oil and natural gas liquids. As of year-end, the Central region s estimated proved reserves totaled 217 MMboe.

Throughout the year, Apache continued to build on its drilling inventory and development opportunities in the Whittenburg basin, located just west of our Anadarko basin properties. Apache s Canyon Wash sand and the prolific Canyon Lime play will be the focus of our region s drilling activity in 2015.

In December 2014, Apache completed the sale of non-core assets in the Anadarko basin, including approximately 115,000 net acres in Wheeler County, Texas, and western Oklahoma, for approximately $730 million. The effective date of the transaction is October 1, 2014.

Canada Region Apache entered the Canadian market in 1995 and currently holds nearly 4.4 million gross acres across the provinces of British Columbia, Alberta, and Saskatchewan. Most of Canada s acreage is held-by-production. The region s large acreage position provides portfolio diversification as well as significant drilling opportunities. Our Canadian region provided approximately 12 percent of Apache s 2014 worldwide production and held 414 MMboe of estimated proved reserves at year-end.

In 2014, Apache drilled or participated in drilling 106 wells in the region with successful results in the established Swan Hills, Viking, Bluesky, and Glauconite developments. In addition, Canada further established key plays in the Duvernay and Montney formations with a focus on reducing drilling and completion costs. In the Duvernay, we began drilling our first seven-well pad and expect to see test rates in the third quarter of 2015. Our Montney drilling has been focused in the Wapiti area.

In our continuing assessment of the Company s North American portfolio, we divested approximately 328,400 net acres in the Ojay, Noel, and Wapiti areas in April 2014. Apache retained 100 percent of its working interest in horizons below the Cretaceous in the Wapiti area, including rights to the liquids-rich Montney and other deeper horizons. We also signed an agreement to divest our working interest in the Kitimat LNG development and approximately 333,000 of our net acres in the Horn River and Liard natural gas basins of British Columbia. The transaction is expected to close in the first quarter of 2015.

North America Offshore

Gulf of Mexico Region The Gulf of Mexico region comprises assets in approximately 617 blocks in the offshore waters of the Gulf of Mexico. In 2014, Apache combined its deepwater and shelf technical teams to focus on subsalt and other deeper exploration opportunities in water depths less than 1,000 feet, which have been relatively untested by the industry. In addition to the exploration and development of properties in shallower water, Apache continues to pursue joint venture and other monetization opportunities for its deepwater prospects, which offer exposure to significant reserve and production potential in underexplored and oil-prone areas in water depths greater than 1,000 feet. During 2014, Apache s Gulf of Mexico region contributed 10.5 Mboe/d to the Company s total production.

On June 30, 2014, Apache completed the sale of non-operated interests in the Lucius and Heidelberg development projects and 11 primary term deepwater exploration blocks to a subsidiary of Freeport-McMoRan Copper & Gold Inc. and other interest owners for $1.4 billion.

North America Marketing

In general, most of our North American gas is sold at either monthly or daily market prices. Also, from time to time, the Company will enter into fixed physical sales contracts for durations of up to one-year. These physical sales volumes are typically sold at fixed prices over the term of the contract. Our natural gas is sold primarily to local distribution companies (LDCs), utilities, end-users, marketers, and integrated major oil companies. We strive to maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk. We transport some of our Canadian natural gas under firm transportation contracts to delivery points into the U.S. in order to diversify our market exposure.

Apache primarily markets its North American crude oil to integrated major oil companies, marketing and transportation companies, and refiners based on a West Texas Intermediate (WTI) price, adjusted for quality, transportation and a market-reflective differential.

In the U.S., our objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices. Also, from time to time, the Company will enter into physical term sales contracts for durations up to five years. These term contracts typically have a firm transport commitment and often provide for the higher of prevailing market prices from multiple market hubs.

In Canada, the crude is transported by pipeline or truck within Western Canada to market hubs in Alberta and Manitoba where it is sold, allowing for a more diversified group of purchasers and a higher netback price. A portion of our trucked barrels are delivered and sold at rail terminals. We evaluate our transport options monthly to maximize our netback prices.

Apache s NGL production is sold under contracts with prices based on local supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

International

Apache s international assets are located in Egypt, Australia, and offshore the U.K. in the North Sea. In 2014, international assets contributed 43 percent of our production and 50 percent of our oil and gas revenues. Approximately 31 percent of our estimated proved reserves at year-end were located outside North America.

Egypt

Overview Our activity in Egypt began in 1994 with our first Qarun discovery well, and today we are one of the largest acreage holders in Egypt s Western Desert. At year-end 2014, we held 6.7 million gross acres, of which approximately 71 percent is undeveloped, providing us with considerable exploration and development opportunities for the future. The region had gross oil production of 197 Mb/d and gross natural gas production of 895 MMcf/d in 2014, or 88 Mb/d and 370 MMcf/d net to Apache s consolidated holdings.

Sinopec holds a one-third minority interest in Apache s Egypt oil and gas business. At December 31, 2014, our Egypt region had estimated proved reserves of 280 MMboe, of which 93 MMboe is attributable to Sinopec s noncontrolling interest. Our estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country s share of reserves.

Our operations in Egypt are conducted pursuant to production-sharing agreements in 24 separate concessions, under which the contractor partners pay all operating and capital expenditure costs for exploration and development. Development leases within concessions currently have expiration dates ranging from 2 to 25 years, with extensions possible for additional commercial discoveries or on a negotiated basis. A percentage of the production on development leases, usually up to 40 percent, is available to the contractor partners to recover operating and capital expenditure costs, with the balance generally allocated between the contractor partners and the Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis.

Our growth in Egypt has been driven by an ongoing drilling program, and we have historically been one of the most active drillers in the Western Desert. We drilled 171 development and 49 exploration wells in 2014. Approximately 45 percent of our exploration wells were successful, further expanding our presence in the westernmost concessions and unlocking additional opportunities in existing plays. A key component of the region s success has been the ability to acquire and evaluate 3-D seismic surveys that enable our technical teams to consistently high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic formations.

Following four years of political turmoil, in January 2014, Egyptians voted on and overwhelmingly approved a new constitution, and in June 2014, Mr. Abdel Fattah el-Sisi was sworn in as president of Egypt.

Apache s operations, located in remote locations in the Western Desert, have not experienced production interruptions, and we have continued to receive development lease approvals for our drilling program. However, a further deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, expropriation of our assets or resource nationalization, and/or forced renegotiation or modification of our existing contracts with EGPC, or threats or acts of terrorism by groups such as ISIS, could materially and adversely affect our business, financial condition, and results of operations.

Marketing Our gas production is sold to EGPC primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content. The region averaged $2.96 per Mcf in 2014.

Oil from the Khalda Concession, the Qarun Concession, and other nearby Western Desert blocks is sold to third parties in the export market or to EGPC when called upon to supply domestic demand. Oil sales are exported from or sold at one of two terminals on the northern coast of Egypt. Oil production that is sold to EGPC is sold on a spot basis priced at Brent with a monthly EGPC official differential applied.

Australia

Overview Apache s holdings in Australia are focused offshore Western Australia in the Carnarvon, Exmouth, and Browse basins, with production operations in the Carnarvon and Exmouth basins. We have operated in the Carnarvon basin since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993. At the end of 2014 we controlled approximately 21 million gross acres offshore Western Australia through 34 exploration permits, 18 production licenses, and 10 retention leases. Over the past decade, the region s exploration activity has established a significant pipeline of projects that are expected to contribute to production growth as they are brought online in the coming years. As of year-end 2014, approximately 96 percent of our acreage is undeveloped. During 2014, the region had net production of 21 Mb/d and 214 MMcf/d, contributing 9 percent of worldwide consolidated production and 13 percent of year-end consolidated proved reserves.

The region participated in drilling 12 offshore wells in 2014, of which 6 were exploration wells. Four of the exploration wells were successful. This compares to 12 wells drilled in the prior year. Development work during the year also continued for the Coniston oil field project, which lies just north of the Van Gogh field. The field

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will be produced via subsea completions tied back to the Ningaloo Vision Floating Production Storage and Offloading Vessel (FPSO) at Van Gogh. Modifications and upgrades to the FPSO are underway, and the final phase of work is planned for the first half of 2015, with first oil production expected shortly thereafter. Apache has a 52.5 percent working interest in the field.

As noted previously, on December 15, 2014, Apache announced an agreement with Woodside Petroleum to sell its 13 percent interest in the Chevron-operated Wheatstone LNG project. The sale also includes Apache s 65 percent interest in the WA-49-L block, which includes the Julimar and Brunello offshore gas fields and the Balnaves oil development. The transaction will have an effective date of June 30, 2014, and under terms of the agreement, Woodside will reimburse Apache for its net expenditure for Wheatstone subsequent to that date. Following the transaction s expected close in the first quarter of 2015, Apache will continue to hold upstream acreage offshore Western Australia in the Carnarvon, Exmouth, and Canning basins along with related hydrocarbon reserves and production.

Marketing Western Australia has historically had a local market for natural gas with a limited number of buyers and sellers resulting in sales under mostly long-term, fixed-price contracts, many of which contain periodic price revision clauses based on either the Australian consumer price index or a commodity linkage. As of December 31, 2014, Apache had 20 active gas contracts in Australia with expiration dates ranging from June 2015 to December 2026. Recent increases in demand and higher development costs have increased the prices required from the local market in order to support the development of new supplies. As a result, market prices negotiated on recent contracts have continued to be higher than historical levels.

We directly market all of our Australian crude oil production into Australian domestic and international markets at prices generally indexed to Dated Brent benchmark crude oil prices plus premiums, which typically result in price realizations above crude sold at WTI-based prices.

North Sea

Overview Apache entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (Forties). Since acquiring Forties, Apache has actively invested in the region and has established a large inventory of drilling prospects through successful exploration programs and the interpretation of acquired 3-D and 4-D seismic data. Building upon its success in Forties, in 2011 Apache acquired Mobil North Sea Limited, providing the region with additional exploration and development opportunities across numerous fields, including operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields and non-operated interests in the Maclure field. In total, Apache has interest in approximately 1 million gross acres in the U.K. North Sea.

In 2014, the North Sea region contributed 11 percent of worldwide consolidated production and 6 percent of year-end estimated proved reserves. In 2014, 22 development wells were drilled in the North Sea, of which 20 were productive. In the Forties area in the Tonto, Maule, and Bacchus fields, Apache has benefited from extensive 4-D seismic interpretations over the last few years and has targeted areas of bypassed oil in the mature reservoir. The Forties Alpha Satellite Platform (FASP) was also commissioned during the third quarter of 2014, providing an additional 18 drilling slots as well as power generation, fluid separation, and gas lift compression.

Marketing We have traditionally sold our North Sea crude oil under both term contracts and spot cargoes. The term sales are composed of a market-based index price plus a premium, which reflects the higher market value for term arrangements. The prices received for spot cargoes are market driven and can trade at a premium or discount to the market-based index.

Natural gas from the Beryl field is processed through the SAGE gas plant operated by Apache. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The condensate mix from the SAGE plant is processed further downstream. The split streams of propane

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and butane are sold on a monthly entitlement basis, and condensate is sold on a spot basis at the Braefoot Bay terminal using index pricing less transportation.

Argentina

On March 12, 2014, Apache s subsidiaries completed the sale of all of the Company s operations in Argentina to YPF Sociedad Anónima for $800 million (subject to customary closing adjustments) plus the assumption of $52 million of bank debt as of June 30, 2013. The results of operations related to Argentina have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K.

Other Exploration

New Ventures

Apache s global New Ventures team provides exposure to new growth opportunities by looking outside of the Company s traditional core areas and targeting higher-risk, higher-reward exploration opportunities located in frontier basins as well as new plays in more mature basins. Plans for 2015 include drilling a deepwater well offshore Suriname.

Major Customers

In 2014, 2013, and 2012 purchases by Royal Dutch Shell plc and its subsidiaries accounted for 19 percent, 24 percent, and 20 percent, respectively, of the Company s worldwide oil and gas production revenues.

Drilling Statistics

Worldwide in 2014 we participated in drilling 1,478 gross wells, with 1,407 (95 percent) completed as producers. Historically, our drilling activities in the U.S. have generally concentrated on exploitation and extension of existing producing fields rather than exploration. As a general matter, our operations outside of the U.S. focus on a mix of exploration and development wells. In addition to our completed wells, at year-end a number of wells had not yet reached completion: 318 gross (214.7 net) in the U.S.; 27 gross (19.0 net) in Canada; 35 gross (32.5 net) in Egypt; and 3 gross (2.2 net) in the North Sea.

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The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years:

	Net Exploratory			Net Development			Total Net Wells		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
2014									
United States	18.5	6.4	24.9	781.5	10.1	791.6	800.0	16.5	816.5
Canada	1.0	1.0	2.0	83.9	2.0	85.9	84.9	3.0	87.9
Egypt	18.6	22.8	41.4	143.3	9.9	153.2	161.9	32.7	194.6
Australia	1.6	1.7	3.3	2.9		2.9	4.5	1.7	6.2
North Sea				17.6	1.1	18.7	17.6	1.1	18.7
Argentina				1.0		1.0	1.0		1.0
Total	39.7	31.9	71.6	1,030.2	23.1	1,053.3	1,069.9	55.0	1,124.9
2013									
United States	15.6	11.2	26.8	834.9	12.6	847.5	850.5	23.8	874.3
Canada				108.5	6.9	115.4	108.5	6.9	115.4
Egypt	30.5	18.7	49.2	141.9	7.3	149.2	172.4	26.0	198.4
Australia	2.2	0.4	2.6	3.4		3.4	5.6	0.4	6.0
North Sea		0.5	0.5	13.4	0.1	13.5	13.4	0.6	14.0
Argentina	2.4		2.4	22.0		22.0	24.4		24.4
Total	50.7	30.8	81.5	1,124.1	26.9	1,151.0	1,174.8	57.7	1,232.5
2012									
United States	9.5	3.5	13.0	746.0	9.6	755.6	755.5	13.1	768.6
Canada	5.0	7.5	12.5	110.3	14.0	124.3	115.3	21.5	136.8
Egypt	28.0	22.5	50.5	144.4	1.0	145.4	172.4	23.5	195.9
Australia	1.9	2.7	4.6	1.3	0.7	2.0	3.2	3.4	6.6
North Sea	1.3		1.3	11.7	3.9	15.6	13.0	3.9	16.9
Argentina	2.0		2.0	23.0		23.0	25.0		25.0
Other International		0.5	0.5					0.5	0.5
Total	47.7	36.7	84.4	1,036.7	29.2	1,065.9	1,084.4	65.9	1,150.3

Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of December 31, 2014, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	14,480	9,610	3,595	1,807	18,075	11,417

Canada	2,050	1,004	2,520	2,010	4,570	3,014
Egypt	1,160	1,100	100	96	1,260	1,196
Australia	45	20	15	8	60	28
North Sea	175	116	25	14	200	130
Total	17,910	11,850	6,255	3,935	24,165	15,785

Gross natural gas and crude oil wells include 640 wells with multiple completions.

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Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGL, and gas production volumes, average lease operating expenses per boe (including transportation costs but excluding severance and other taxes), and average sales prices for each of the countries where we have operations:

	Production			Average Lease	Average Sales Price		
Year Ended December 31,	**Oil (MMbbls)**	**NGLs (MMbbls)**	**Gas (Bcf)**	**Operating Cost per Boe**	**Oil (Per bbl)**	**NGLs (Per bbl)**	**Gas (Per Mcf)**
2014							
United States	48.7	21.5	215.8	$ 9.55	$ 87.33	$ 25.57	$ 4.33
Canada	6.4	2.3	117.8	17.90	83.57	33.61	4.07
Egypt(1)	32.1	0.2	135.1	9.83	97.44	51.80	2.96
Australia	7.5		78.1	11.73	94.99		4.43
North Sea	22.2	0.5	20.5	17.30	95.53	59.42	8.29
Total	116.9	24.5	567.3	11.67	91.94	27.28	4.11
2013							
United States	53.6	19.9	285.2	$ 11.60	$ 98.14	$ 27.29	$ 3.84
Canada	6.5	2.4	181.6	15.68	87.00	30.50	3.23
Egypt(1)	32.7		130.1	9.42	107.94		2.99
Australia	7.0		81.5	10.35	110.42		4.43
North Sea	23.3	0.5	18.6	15.16	107.48	73.06	10.43
Total	123.1	22.8	697.0	12.02	102.62	28.56	3.77
2012							
United States	49.1	12.3	312.6	$ 12.83	$ 94.98	$ 32.19	$ 3.74
Canada	5.8	2.3	219.9	13.87	84.89	34.63	3.42
Egypt	36.5		129.5	7.73	110.92		3.90
Australia	10.6		78.3	9.08	115.22		4.55
North Sea	23.3	0.6	21.0	12.38	107.97	77.11	8.95
Total	125.3	15.2	742.4	11.52	103.29	34.31	3.90

(1) Includes production volumes attributable to a one-third noncontrolling interest in Egypt

Gross and Net Undeveloped and Developed Acreage

The following table sets out our gross and net acreage position as of December 31, 2014, in each country where we have operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)			
United States	8,164	4,080	2,321	1,188
Canada	1,735	1,179	2,648	1,918
Egypt	4,824	3,537	1,925	1,761
Australia	20,085	11,794	900	545
North Sea	837	375	183	122
Total	35,645	20,965	7,977	5,534

As of December 31, 2014, Apache had 3.1 million net undeveloped acres scheduled to expire by year-end 2015 if production is not established or we take no other action to extend the terms. Additionally, Apache has

1.7 million and 1.9 million net undeveloped acres set to expire in 2016 and 2017, respectively. We strive to extend the terms of many of these licenses and concession areas through operational or administrative actions, but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third parties including governments.

Exploration concessions in our Egypt region comprise a significant portion of our net undeveloped acreage expiring over the next three years. We have 1.0 million net undeveloped acres set to expire in 2015 and 2016. Apache will continue to pursue acreage extensions in areas in which it believes exploration opportunities exist and over the past year has been successful in being awarded six-month extensions on targeted concessions. Longer term extensions are also being finalized with EGPC. In Australia, 1.4 million, 0.4 million and 1.1 million net undeveloped acres are scheduled to expire in 2015, 2016 and 2017, respectively. There were no reserves recorded on this undeveloped acreage.

Separately, with the announced divestiture of our Kitimat and Wheatstone LNG projects, an additional 79,000 net undeveloped acres and 100,000 net developed acres in Australia and 330,000 net undeveloped acres in Canada will be sold as a part of the transaction.

As of December 31, 2014, 23 percent of U.S. net undeveloped acreage and 63 percent of Canadian undeveloped acreage was held by production.

Estimated Proved Reserves and Future Net Cash Flows

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate, and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods. The Company reports all estimated proved reserves held under production-sharing arrangements utilizing the economic interest method, which excludes the host country s share of reserves.

Estimated reserves that can be produced economically through application of improved recovery techniques are included in the proved classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating its proved reserves, Apache uses several different traditional methods that can be classified in three general categories: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy with similar properties. Apache will, at times, utilize additional technical analysis, such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods, to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of our reserve estimates.

Proved undeveloped reserves include those 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. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time period.

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The following table shows proved oil, NGL, and gas reserves as of December 31, 2014, based on average commodity prices in effect on the first day of each month in 2014, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. This table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products.

	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Total (MMboe)
Proved Developed:				
United States	444	184	1,616	897
Canada	76	18	990	259
Egypt[1]	129	1	637	236
Australia	30		640	137
North Sea	105	2	87	122
Total Proved Developed	784	205	3,970	1,651
Proved Undeveloped:				
United States	170	70	580	337
Canada	60	7	528	155
Egypt[1]	15		172	44
Australia	26		965	186
North Sea	19		23	23
Total Proved Undeveloped	290	77	2,268	745
TOTAL PROVED	1,074	282	6,238	2,396

(1) Includes total proved reserves of 93 MMboe attributable to a one-third noncontrolling interest in Egypt

As of December 31, 2014, Apache had total estimated proved reserves of 1,074 MMbbls of crude oil, 282 MMbbls of NGLs, and 6.2 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 2.4 billion barrels of oil or 14.4 Tcf of natural gas, of which oil represents 44.8 percent. As of December 31, 2014, the Company s proved developed reserves totaled 1,651 MMboe and estimated PUD reserves totaled 745 MMboe, or approximately 31 percent of worldwide total proved reserves. Apache has elected not to disclose probable or possible reserves in this filing.

The Company s estimates of proved reserves, proved developed reserves and PUD reserves as of December 31, 2014, 2013, and 2012, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 14 Supplemental Oil and Gas Disclosures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. Estimated future net cash flows were calculated using a discount rate of 10 percent per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

Proved Undeveloped Reserves

The Company s total estimated PUD reserves of 745 MMboe as of December 31, 2014, decreased by 68 MMboe from 813 MMboe of PUD reserves estimated at the end of 2013. During the year, Apache converted 134 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America, we converted 108 MMboe, with the remaining 26 MMboe in our international areas. We sold 150 MMboe and acquired 18 MMboe of PUD reserves during the year. We added 197 MMboe of new PUD reserves through extensions and discoveries.

During the year, a total of approximately $3.6 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2013. A portion of our costs incurred each year relate to development projects that will be converted to proved developed reserves in future years. We spent $1.9 billion on PUD reserve development activity in North America and $1.7 billion in the international areas. Other than our Julimar/Brunello development project, which is tied to the construction schedule of the Wheatstone LNG project, with projected first production in 2016, we had no material amounts of PUD reserves that have remained undeveloped for five years or more after they were initially disclosed as PUD reserves and no material amounts of PUD reserves which are scheduled to be developed beyond five years from December 31, 2014.

Preparation of Oil and Gas Reserve Information

Apache s reported reserves are reasonably certain estimates which, by their very nature, are subject to revision. These estimates are reviewed throughout the year and revised either upward or downward, as warranted.

Apache s proved reserves are estimated at the property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers that is independent of the operating groups. These engineers interact with engineering and geoscience personnel in each of Apache s operating areas and with accounting and marketing employees to obtain the necessary data for projecting future production, costs, net revenues, and ultimate recoverable reserves. All relevant data is compiled in a computer database application, to which only authorized personnel are given security access rights consistent with their assigned job function. Reserves are reviewed internally with senior management and presented to Apache s Board of Directors in summary form on a quarterly basis. Annually, each property is reviewed in detail by our corporate and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable.

Apache s Executive Vice President of Corporate Reservoir Engineering is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating any reserves audits conducted by a third-party engineering firm. He has a Bachelor of Science degree in Petroleum Engineering and over 30 years of industry experience with positions of increasing responsibility within Apache s corporate reservoir engineering department. The Executive Vice President of Corporate Reservoir Engineering reports directly to our Chief Executive Officer.

The estimate of reserves disclosed in this Annual Report on Form 10-K is prepared by the Company s internal staff, and the Company is responsible for the adequacy and accuracy of those estimates. However, the Company engages Ryder Scott Company, L.P. Petroleum Consultants (Ryder Scott) to review our processes and the reasonableness of our estimates of proved hydrocarbon liquid and gas reserves. Apache selects the properties for review by Ryder Scott based primarily on relative reserve value. We also consider other factors such as geographic location, new wells drilled during the year and reserves volume. During 2014, the properties selected for each country ranged from 83 to 100 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 96 percent of the reserves value of our international proved reserves and of the new wells drilled in each country. In addition, all fields containing five percent or more of the Company s total proved reserves volume were included in Ryder Scott s review. The review covered 85 percent of total proved reserves, including 91 percent of proved developed reserves and 72 percent of PUD reserves.

During 2014, 2013, and 2012, Ryder Scott s review covered 91, 92, and 88 percent, respectively, of the Company s worldwide estimated proved reserves value and 85, 86, and 83 percent, respectively, of the Company s total proved reserves volume. Ryder Scott s review of 2014 covered 83 percent of U.S, 75 percent of Canada, 99.5 percent of Australia, 86 percent of Egypt, and 94 percent of the U.K. s total proved reserves.

Ryder Scott s review of 2013 covered 84 percent of U.S., 82 percent of Canada, 63 percent of Argentina, 99 percent of Australia, 88 percent of Egypt, and 88 percent of the U.K. s total proved reserves.

Ryder Scott s review of 2012 covered 81 percent of U.S., 78 percent of Canada, 64 percent of Argentina, 99 percent of Australia, 84 percent of Egypt, and 88 percent of the U.K. s total proved reserves.

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We have filed Ryder Scott s independent report as an exhibit to this Form 10-K.

According to Ryder Scott s opinion, based on their review, including the data, technical processes, and interpretations presented by Apache, the overall procedures and methodologies utilized by Apache in determining the proved reserves comply with the current SEC regulations, and the overall proved reserves for the reviewed properties as estimated by Apache are, in aggregate, reasonable within the established audit tolerance guidelines as set forth in the Society of Petroleum Engineers auditing standards.

Employees

On December 31, 2014, we had 4,950 employees.

Offices

Our principal executive offices are located at One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400. At year-end 2014, we maintained regional exploration and/or production offices in Midland, Texas; San Antonio, Texas; Tulsa, Oklahoma; Houston, Texas; Calgary, Alberta; Cairo, Egypt; Perth, Western Australia; and Aberdeen, Scotland. Apache leases all of its primary office space. The current lease on our principal executive offices runs through December 31, 2018. For information regarding the Company s obligations under its office leases, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Contractual Obligations and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Title to Interests

As is customary in our industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time we acquire properties. We believe that our title to all of the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in our operations. The interests owned by us may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as production payments, net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in our operations.

Additional Information about Apache

In this section, references to we, us, our, and Apache include Apache Corporation and its consolidated subsidiaries, unless otherwise specifically stated.

Remediation Plans and Procedures

Apache and its wholly owned subsidiary, Apache Deepwater LLC (ADW), developed Oil Spill Response Plans (the Plans) for their respective Gulf of Mexico operations to ensure rapid and effective responses to spill events that may occur on such entities operated properties as required by the Bureau of Safety and Environmental Enforcement (BSEE). Annually, drills are conducted to measure and maintain the effectiveness of the Plans. These drills include the participation of spill response contractors, representatives of Clean Gulf Associates (CGA), and representatives of governmental agencies.

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In the event of a spill, CGA is the primary oil spill response association available to Apache and ADW. Both Apache and ADW are members of CGA, a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico. CGA was created to provide a means of effectively staging response equipment and providing immediate spill response for its member companies operations in the Gulf of Mexico. In the event of a spill, CGA s equipment, which is positioned at various staging points around the Gulf, is ready to be mobilized.

In the event that CGA resources are already being utilized, other resources are available to Apache. Apache is a member of Oil Spill Response Limited (OSRL), which entitles any Apache entity worldwide to access OSRL s service. In addition, ADW is a member of Marine Spill Response Corporation (MSRC) and National Response Corporation (NRC), and their resources are available to ADW for its deepwater Gulf of Mexico operations. The equipment and resources available to MSRC and NRC changes from time to time, and current information is generally available on each company s website.

An Apache subsidiary is also a member of the Marine Well Containment Company (MWCC) to help the Company fulfill the government s permit requirements for containment and oil spill response plans in deepwater Gulf of Mexico operations. MWCC is a not-for-profit, stand-alone organization whose goal is to improve capabilities for containing an underwater well control incident in the U.S. Gulf of Mexico. Members and their affiliates have access to MWCC s extensive containment network and systems. As of December 31, 2014, Apache s investment in MWCC totals approximately $170 million.

Competitive Conditions

The oil and gas business is highly competitive in the exploration for and acquisitions of reserves, the acquisition of oil and gas leases, equipment and personnel required to find and produce reserves, and in the gathering and marketing of oil, gas, and natural gas liquids. Our competitors include national oil companies, major integrated oil and gas companies, other independent oil and gas companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers.

Certain of our competitors may possess financial or other resources substantially larger than we possess or have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for leases or drilling rights.

However, we believe our diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across five countries, our balanced production mix between oil and gas, our management and incentive systems, and our experienced personnel give us a strong competitive position relative to many of our competitors who do not possess similar geographic and production diversity. Our global position provides a large inventory of geologic and geographic opportunities in the five countries in which we have producing operations to which we can reallocate capital investments in response to changes in commodity prices, local business environments, and markets. It also reduces the risk that we will be materially impacted by an event in a specific area or country.

Environmental Compliance

As an owner or lessee and operator of oil and gas properties and facilities, we are subject to numerous federal, provincial, state, local, and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Although environmental requirements have a substantial impact upon the energy industry, as a whole, we do not believe that these requirements affect us differently, to any material degree, than other companies in our industry.

We have made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry. We have established policies for continuing compliance with environmental laws and regulations, including regulations applicable to our operations in all countries in which we do business. We have established operating procedures and training programs designed to limit the environmental impact of our field facilities and identify and comply with changes in existing laws and regulations. The costs incurred under these policies and procedures are inextricably connected to normal operating expenses such that we are unable to separate expenses related to environmental matters; however, we do not believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on our capital expenditures, earnings, or competitive position.

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ITEM 1A. *RISK FACTORS*

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Additional risks relating to our securities may be included in the prospectuses for securities we issue in the future.

Crude oil and natural gas price volatility, including the recent decline in prices for oil and natural gas, could adversely affect our operating results and the price of our common stock.

Our revenues, operating results, and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2014 ranged from a high of $107.26 per barrel to a low of $53.27 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2014 ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu. The market prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions, and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability, changes in governments, or armed conflict) in crude oil or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil and natural gas;
- the price and availability of alternative fuels, including coal and biofuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;

- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Our results of operations, as well as the carrying value of our oil and gas properties, are substantially dependent upon the prices of oil and natural gas, which have declined significantly since June 2014. Lower crude oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, and/or ability to fund planned capital expenditures and operations;
- reducing the amount of crude oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income, and cash flows;
- limiting our access to sources of capital, such as equity and long-term debt;
- reducing the carrying value of our crude oil and natural gas properties resulting in additional non-cash write-downs; or
- reducing the carrying value of goodwill.

Our ability to sell natural gas or oil and/or receive market prices for our natural gas or oil may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

A portion of our natural gas and oil production in any region may be interrupted, limited, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or capital constraints that limit the ability of third parties to construct gathering systems, processing facilities, or interstate pipelines to transport our production, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows.

Future economic conditions in the U.S. and certain international markets may materially adversely impact our operating results.

Current global market conditions, and uncertainty, including economic instability in Europe and certain emerging markets, is likely to have significant long-term effects. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

Weather and climate may have a significant adverse impact on our revenues and productivity.

Demand for oil and natural gas are, to a degree, dependent on weather and climate, which impact the price we receive for the commodities we produce. In addition, our exploration and development activities and equipment can be adversely affected by severe weather, such as freezing temperatures, hurricanes in the Gulf of Mexico, storms in the North Sea, or cyclones offshore Australia, which may cause a loss of production from temporary cessation of activity or lost or damaged equipment. Our planning for normal climatic variation, insurance programs, and emergency recovery plans may inadequately mitigate the effects of such weather conditions, and not all such effects can be predicted, eliminated, or insured against.

Our operations involve a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents.

Our operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil and natural gas, including:

- well blowouts, explosions, and cratering;
- pipeline or other facility ruptures and spills;
- fires;
- formations with abnormal pressures;

equipment malfunctions;

hurricanes, storms, and/or cyclones, which could affect our operations in areas such as on- and offshore the Gulf Coast, North Sea, and Australia, and other natural disasters and weather conditions; and

surface spillage and surface or ground water contamination from petroleum constituents, saltwater, or hydraulic fracturing chemical additives.

Failure or loss of equipment as the result of equipment malfunctions, cyber attacks, or natural disasters such as hurricanes, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, or fire at a location where our equipment and services are used, or ground water contamination from hydraulic fracturing chemical additives may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture, or surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives could result in extensive environmental pollution and substantial remediation expenses. If a significant amount of our production is interrupted, our containment efforts prove to be ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and, in turn, our results of operations could be materially and adversely affected.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate with our employees and third party partners, and conduct many of our activities. Unauthorized access to our digital technology could lead to operational disruption, data corruption or exposure, communication interruption, loss of intellectual property, loss of confidential and fiduciary data, loss or corruption of reserves or other proprietary information. Also, digital technologies control nearly all of the oil and gas distribution and refining systems in the United States and abroad which are necessary to transport and market our production. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have experienced cyber attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

The enactment of new or stricter laws and regulations and other related developments in the Gulf of Mexico as well as our other locations following the Deepwater Horizon incident could adversely affect Apache s business.

In response to the Deepwater Horizon incident in the U.S. Gulf of Mexico in April 2010, and as directed by the Secretary of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) issued new guidelines and regulations regarding safety, environmental matters, drilling equipment, and decommissioning applicable to drilling in the Gulf of Mexico. These new regulations imposed additional requirements with respect to development and production activities in the Gulf of Mexico and delayed the approval of applications to drill in both deepwater and shallow-water areas.

The enactment of new or stricter regulations in the United States and other countries and increased liability for companies operating in this sector could adversely affect Apache s operations in the U.S. Gulf of Mexico as well as in our other locations.

Our commodity price risk management and trading activities may prevent us from benefiting fully from price increases and may expose us to other risks.

To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from realizing the benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

our production falls short of the hedged volumes;

there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;

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the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or

an unexpected event materially impacts oil and natural gas prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds, and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We are exposed to counterparty credit risk as a result of our receivables.

We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas, and NGLs to a variety of purchasers. As operator, we pay expenses and bill our non-operating partners for their respective shares of costs. Some of our purchasers and non-operating partners may experience liquidity problems and may not be able to meet their financial obligations. Nonperformance by a trade creditor or non-operating partner could result in significant financial losses.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, and commodity pricing levels and others are also considered by the rating agencies. We have been placed on negative watch by one rating agency and negative outlook by another rating agency. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require us to post letters of credit or other forms of collateral for certain obligations.

Market conditions may restrict our ability to obtain funds for future development and working capital needs, which may limit our financial flexibility.

The credit markets are subject to fluctuation and are vulnerable to unpredictable shocks. We have a significant development project inventory and an extensive exploration portfolio, which will require substantial future investment. We and/or our partners may need to seek financing in order to fund these or other future activities. Our future access to capital, as well as that of our partners and contractors, could be limited if the debt or equity markets are constrained. This could significantly delay development of our property interests.

Our ability to declare and pay dividends is subject to limitations.

The payment of future dividends on our capital stock is subject to the discretion of our board of directors, which considers, among other factors, our operating results, overall financial condition, credit-risk considerations, and capital requirements, as well as general business and market conditions. Our board of directors is not required to declare dividends on our common stock and may decide not to declare dividends.

Any indentures and other financing agreements that we enter into in the future may limit our ability to pay cash dividends on our capital stock, including common stock. In addition, under Delaware law, dividends on capital stock may only be paid from surplus, which is defined as the amount by which our total assets exceeds

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the sum of our total liabilities, including contingent liabilities, and the amount of our capital; if there is no surplus, cash dividends on capital stock may only be paid from our net profits for the then current and/or the preceding fiscal year. Further, even if we are permitted under our contractual obligations and Delaware law to pay cash dividends on common stock, we may not have sufficient cash to pay dividends in cash on our common stock.

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.

The production rate from oil and gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through exploration and development activities or, through engineering studies, identify additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase.

We may not realize an adequate return on wells that we drill.

Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The wells we drill or participate in may not be productive, and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors including, but not limited to:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts, and surface cratering;
- marine risks such as capsizing, collisions, and hurricanes;
- other adverse weather conditions; and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Future drilling activities may not be successful, and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.

Material differences between the estimated and actual timing of critical events or costs may affect the completion and commencement of production from development projects.

We are involved in several large development projects and the completion of these projects may be delayed beyond our anticipated completion dates. Our projects may be delayed by project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, and other unforeseen events. Delays and differences between estimated and actual timing of critical events may adversely affect our large development projects and our ability to participate in large-scale development projects in the future. In addition, our estimates of future development costs are based on current expectation of prices and other costs of equipment and personell we will need to

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implement such projects. Our actual future development costs may be significantly higher than we currently estimate. If costs become too high, our development projects may become uneconomic to us and we may be forced to abandon such development projects.

We may fail to fully identify potential problems related to acquired reserves or to properly estimate those reserves.

Although we perform a review of properties that we acquire that we believe is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in-depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us as a buyer to become sufficiently familiar with the properties to assess fully and accurately their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future production rates and costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates. In addition, there can be no assurance that acquisitions will not have an adverse effect upon our operating results, particularly during the periods in which the operations of acquired businesses are being integrated into our ongoing operations.

The BP Acquisition and/or our liabilities could be adversely affected in the event one or more of the BP entities become the subject of a bankruptcy case.

In the event that one or more of the BP entities were to become the subject of a case or proceeding under Title 11 of the United States Code or any other relevant insolvency law or similar law (which we collectively refer to as Insolvency Laws), a court may find that the three definitive purchase and sale agreements (the BP Purchase Agreements) we entered into in connection with our 2010 acquisition of properties from BP (the BP Properties) are executory contracts, in which case such BP entities may, subject to relevant Insolvency Laws, have the right to reject the agreements and refuse to perform their future obligations under them. In this event, our ability to enforce our rights under the BP Purchase Agreements could be adversely affected.

Additionally, in a case or proceeding under relevant Insolvency Laws, a court may find that the sale of the BP Properties constitutes a constructive fraudulent conveyance that should be set aside. While the tests for determining whether a transfer of assets constitutes a constructive fraudulent conveyance vary among jurisdictions, such a determination generally requires that the seller received less than a reasonably equivalent value in exchange for such transfer or obligation and the seller was insolvent at the time of the transaction, or was rendered insolvent or left with unreasonably small capital to meet its anticipated business needs as a result of the transaction. The applicable time periods for such a finding also vary among jurisdictions, but generally range from two to six years. If a court were to make such a determination in a proceeding under relevant Insolvency Laws, our rights under the BP Purchase Agreements, and our rights to the BP Properties, could be adversely affected.

Crude oil and natural gas reserves are estimates, and actual recoveries may vary significantly.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices, except where contractual arrangements exist; therefore, reserves quantities will change when actual prices increase or decrease.

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In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the effects of regulations by governmental agencies, including changes to severance and excise taxes;
- future operating costs and capital expenditures; and
- workover and remediation costs.

For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of those reserves and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

Additionally, because some of our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A sizeable portion of our acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling, and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

We may incur significant costs related to environmental matters.

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, provincial, state, local, and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up and other remediation activities resulting from operations, subject the lessee to liability for pollution and other damages, limit or constrain operations in affected areas, and require suspension or cessation of operations in affected areas. Our efforts to limit our exposure to such liability and cost may prove inadequate and result in significant adverse effects to our results of operations. In addition, it is possible that the increasingly strict requirements imposed by environmental laws and enforcement policies could require us to make significant capital expenditures. Such capital expenditures could adversely impact our cash flows and our financial condition.

Our North American operations are subject to governmental risks that may impact our operations.

Our North American operations have been, and at times in the future may be, affected by political developments and by federal, state, provincial, and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls, and environmental protection laws and regulations. New political developments, laws, and regulations may adversely impact our results of operations.

Pending regulations related to emissions and the impact of any changes in climate could adversely impact our business.

Certain countries where we operate, including Canada and the United Kingdom, either tax or assess some form of greenhouse gas (GHG) related fees on our operations. Exposure has not been material to date, although a change in existing regulations could adversely affect our cash flows and results of operations.

In the event the predictions for rising temperatures and sea levels suggested by reports of the United Nations Intergovernmental Panel on Climate Change do transpire, we do not believe those events by themselves are likely to impact our assets or operations. However, any increase in severe weather could have a material adverse effect on our assets and operations.

The proposed U.S. federal budget for fiscal year 2016 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 2, 2015, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2016. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies. These provisions include elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; repeal of the manufacturing tax deduction for oil and natural gas companies; and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities in the U.S. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by impacting our use of derivative instruments as hedges against fluctuating commodity prices.

The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation. The Act provides for a potential exception from these clearing and collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. We expect to qualify as a commercial end-user. As required by the Dodd-Frank Act, the Commodities Futures and Trading Commission (CFTC) has promulgated numerous rules to define these terms. The CFTC, in conjunction with prudential regulators, have proposed rules for financial counterparties entering into swap transactions with end-users that do not mandate margin. Further, a recent piece of legislation, the Terrorism Risk Insurance Program Reauthorization Act of 2015, amended the Dodd-Frank Act such that neither the CFTC nor the prudential regulators can enact rules requiring mandatory margin from entities that qualify as commercial end-users. However, the CFTC is expected to issue rules regarding capital requirements for swap dealers later this year. These rules could cause swap dealers subject to them, to seek to require collateral from their counterparties to avoid reserving balance sheet against exposures.

From time to time, we use derivative instruments with respect to a portion of our expected crude oil and natural gas production in order to reduce the impact of commodity price fluctuations and enhance the stability of cash flows to support our capital investment programs and acquisitions. Given our current investment grade status, we would not anticipate that our derivative contracts should require the posting of margin regardless of the size of our liability positions. However, depending on the rules and definitions adopted by the CFTC, our counterparties may be subject to regulation that could cause them to seek that we post significant amounts of collateral with our dealer counterparties for derivative transactions to avoid capital charges by their regulator. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and also cause us to incur additional debt and/or reduce capital investment.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase our operating and capital costs.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to potential environmental and physical impacts, including possible contamination of groundwater and drinking water and possible links to earthquakes. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing, or are considering doing so. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in very tight formations.

Although it is not possible at this time to predict the final outcome of the legislation regarding hydraulic fracturing, any new federal, state, or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions in the U.S.

A deterioration of conditions in Egypt or changes in the economic and political environment in Egypt could have an adverse impact on our business.

Deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, expropriation of our assets or resource nationalization, and/or forced renegotiation or modification of our existing contracts with EGPC, or threats or acts of terrorism by groups such as ISIS, could materially and adversely affect our business, financial condition, and results of operations. Our operations in Egypt contributed 23 percent of our 2014 production and accounted for 12 percent of our year-end estimated proved reserves. At year-end 2014, 18 percent of our estimated discounted future net cash flows and 9 percent of our net capitalized oil and gas property was attributable to Egypt. These totals reflect our consolidated interests in Egypt including Sinopec s one-third noncontrolling interest.

International operations have uncertain political, economic, and other risks.

Our operations outside North America are based primarily in Egypt, Australia, and the United Kingdom. On a barrel equivalent basis, approximately 43 percent of our 2014 production was outside North America, and approximately 31 percent of our estimated proved oil and gas reserves on December 31, 2014, were located outside North America. As a result, a significant portion of our production and resources are subject to the increased political and economic risks and other factors associated with international operations including, but not limited to:

- general strikes and civil unrest;

the risk of war, acts of terrorism, expropriation and resource nationalization, forced renegotiation or modification of existing contracts;

import and export regulations;

taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;

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- price control;
- transportation regulations and tariffs;
- constrained natural gas markets dependent on demand in a single or limited geographical area;
- exchange controls, currency fluctuations, devaluation, or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the United States affecting foreign trade, including trade sanctions;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;
- the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the United States; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

Foreign countries have occasionally asserted rights to oil and gas properties through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to us by another country, our interests could decrease in value or be lost. Even our smaller international assets may affect our overall business and results of operations by distracting management s attention from our more significant assets. Certain regions of the world in which we operate have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might result in a substantially more hostile attitude toward foreign investments such as ours. In an extreme case, such a change could result in termination of contract rights and expropriation of our assets. This could adversely affect our interests and our future profitability.

The impact that future terrorist attacks by groups such as ISIS or regional hostilities as have occurred in Egypt and Libya may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants, and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

Our operations are sensitive to currency rate fluctuations.

Our operations are sensitive to fluctuations in foreign currency exchange rates, particularly between the U.S. dollar and the Canadian dollar, the Australian dollar, and the British Pound. Our financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect our results of operations, particularly through the weakening of the U.S. dollar relative to other currencies.

We face strong industry competition that may have a significant negative impact on our results of operations.

Strong competition exists in all sectors of the oil and gas exploration and production industry. We compete with major integrated and other independent oil and gas companies for acquisition of oil and gas leases, properties, and reserves, equipment, and labor required to explore, develop, and operate those properties, and marketing of oil and natural gas production. Crude oil and natural gas prices impact the costs of properties available for acquisition and the number of companies with the financial resources to pursue acquisition opportunities. Many of our competitors have financial and other resources substantially larger than we possess and have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as fluctuating worldwide commodity prices and levels of production, the cost and availability of alternative fuels, and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. These competitive pressures may have a significant negative impact on our results of operations.

Our insurance policies do not cover all of the risks we face, which could result in significant financial exposure.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other events such as blowouts, cratering, fire and explosion and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property and the environment. Our international operations are also subject to political risk. The insurance coverage that we maintain against certain losses or liabilities arising from our operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to us against all operational risks.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

As of December 31, 2014, we did not have any unresolved comments from the SEC staff that were received 180 or more days prior to year-end.

ITEM 3. *LEGAL PROCEEDINGS*

The information set forth under Legal Matters and Environmental Matters in Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. *MINE SAFETY DISCLOSURES*

None.

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PART II

ITEM 5. *MARKET FOR THE REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

During 2014, Apache common stock, par value $0.625 per share, was traded on the New York and Chicago Stock Exchanges and the NASDAQ National Market under the symbol APA. The table below provides certain information regarding our common stock for 2014 and 2013. Prices were obtained from The New York Stock Exchange, Inc. Composite Transactions Reporting System. Per-share prices and quarterly dividends shown below have been rounded to the indicated decimal place.

	2014				2013			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 87.91	$ 77.31	$ 0.25	$ 0.20	$ 86.35	$ 72.20	$ 0.20	$ 0.17
Second Quarter	102.34	81.87	0.25	0.25	87.57	67.91	0.20	0.20
Third Quarter	104.57	92.84	0.25	0.25	89.17	75.07	0.20	0.20
Fourth Quarter	93.87	54.34	0.25	0.25	94.84	84.15	0.20	0.20

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 30, 2015 (last trading day of the month), was $62.57 per share. As of January 31, 2015, there were 376,823,368 shares of our common stock outstanding held by approximately 4,700 stockholders of record and 270,000 beneficial owners.

We have paid cash dividends on our common stock for 50 consecutive years through December 31, 2014. In the first quarter of 2014 the Board of Directors approved a 25 percent increase to $0.25 per share for the regular quarterly cash dividend on the Company s common shares. When, and if, declared by our Board of Directors, future dividend payments will depend upon our level of earnings, financial requirements, and other relevant factors.

In 1995, under our stockholder rights plan, each of our common stockholders received a dividend of one preferred stock purchase right (a Right) for each 2.310 outstanding shares of common stock (adjusted for subsequent stock dividends and a two-for-one stock split) that the stockholder owned. These Rights were originally scheduled to expire on January 31, 2006. Effective as of that date, the Rights were reset to one right per share of common stock, and the expiration was extended to January 31, 2016.

On February 5, 2014, the Company s Board of Directors voted to terminate the Company s stockholder rights plan. As a result of this decision, the Board approved an amendment to the Rights Agreement that had the effect of terminating the Rights. The amendment changed the expiration date to March 7, 2014, and, thereby, accelerated the expiration of the Rights. The amendment was fully executed on March 7, 2014.

Information concerning securities authorized for issuance under equity compensation plans is set forth under the caption Equity Compensation Plan Information in the proxy statement relating to the Company s 2015 annual meeting of stockholders, which is incorporated herein by reference.

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The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company s common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company s common stock with the cumulative total return of the Standard & Poor s Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 31, 2009, through December 31, 2014. The stock performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

	2009	2010	2011	2012	2013	2014
Apache Corporation	$ 100.00	$ 116.26	$ 88.79	$ 77.51	$ 85.66	$ 63.18
S & P s Composite 500 Stock Index	100.00	115.06	117.49	136.30	180.44	205.14
DJ US Expl & Prod Index	100.00	116.74	111.85	118.36	156.05	139.24

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Issuer Purchases of Equity Securities

The table below sets forth information with respect to shares of common stock repurchased by Apache during 2014.

Period	Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
January 1 to January 31, 2014	1,164,817	$ 85.84	1,164,817	17,613,264
February 1 to February 28, 2014	1,020,100	84.23	1,020,100	16,593,164
March 1 to March 31, 2014	3,734,166	80.00	3,734,166	12,858,998
April 1 to April 30, 2014	4,431,031	84.46	4,431,031	8,427,967
May 1 to May 31, 2014	2,876,000	88.04	2,876,000	15,551,967
June 1 to June 30, 2014	1,629,305	93.70	1,629,305	13,922,662
July 1 to July 31, 2014				13,922,662
August 1 to August 31, 2014	2,504,119	99.68	2,504,119	11,418,543
September 1 to September 30, 2014	3,239,674	97.93	3,239,674	8,178,869
October 1 to October 31, 2014	351,517	94.07	351,517	7,827,352
November 1 to November 30, 2014				7,827,352
December 1 to December 31, 2014				7,827,352
Total	20,950,729	$ 89.00		

(1) In May 2013, the Company announced that its Board of Directors authorized the repurchase of up to 30 million shares of the Company s common stock. Additionally, on May 15, 2014, the Company announced that the Board of Directors had authorized the repurchase of an additional 10 million shares, supplementing the May 2013 authorization. The Company may buy shares from time to time on the open market, in privately negotiated transactions, or a combination of both. The timing and amounts of any repurchases will be at the discretion of Apache s management and will depend on a variety of factors, including the stock price, corporate and regulatory requirements, and other market and economic conditions. Repurchased shares will be available for general corporate purposes.

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ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth selected financial data of the Company and its consolidated subsidiaries over the five-year period ended December 31, 2014, which information has been derived from the Company s audited financial statements. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in the Company s financial statements set forth in Part IV, Item 15 of this Form 10-K. As discussed in more detail under Item 15, 2014 numbers in the following table reflect a total of $5.0 billion ($3.1 billion net of tax) in non-cash write-downs of the carrying value of the Company s U.S. and North Sea proved oil and gas properties as a result of ceiling test limitations and asset impairments totaling $2.4 billion ($2.1 billion net of tax) in connection with fair value assessments, including $1.3 billion for the impairment of goodwill, $1.0 billion for the impairment of assets held for sale, and other asset impairments. The 2013 numbers reflect a total of $995 million ($541 million net of tax) in non-cash write-downs of the carrying value of the Company s U.S. and North Sea proved oil and gas properties as a result of ceiling test limitations and a non-cash write-down related to the Company s exit of operations in Kenya. The 2012 numbers reflect a total of $1.9 billion ($1.4 billion net of tax) in non-cash write-downs of the carrying value of the Company s Canadian proved oil and gas properties.

	As of or for the Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
	(In millions, except per share amounts)				
Income Statement Data					
Total revenues	$ 13,851	$ 15,560	$ 16,564	$ 16,451	$ 11,742
Net income (loss) from continuing operations attributable to common shareholders	(4,886)	2,380	1,911	4,496	2,968
Net income (loss) from continuing operations per share:					
Basic	(12.72)	6.02	4.91	11.72	8.44
Diluted	(12.72)	5.97	4.89	11.44	8.37
Cash dividends declared per common share	1.00	0.80	0.68	0.60	0.60
Balance Sheet Data					
Total assets	$ 55,952	$ 61,637	$ 60,737	$ 52,051	$ 43,425
Long-term debt	11,245	9,672	11,355	6,785	8,095
Total equity	28,137	35,393	31,331	28,993	24,377
Common shares outstanding	377	396	392	384	382

For a discussion of significant acquisitions and divestitures, see Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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ITEM 7. *MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. We currently have exploration and production interests in five countries: the U.S., Canada, Egypt, Australia, and the U.K. North Sea. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities.

The following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K, and the risk factors and related information set forth in Part I, Item 1A and Part II, Item 7A of this Form 10-K.

Executive Overview

Strategy

Apache s mission is to grow a profitable global exploration and production company in a safe and environmentally responsible manner for the long-term benefit of our shareholders. Our growth strategy focuses on economic growth through exploration and development drilling, supplemented by occasional strategic acquisitions and portfolio high-grading through asset divestitures.

The Company s foundation for future growth is driven by our significant producing asset base and large undeveloped acreage positions. This allows for growth through sustainable lower-risk drilling opportunities, balanced by higher-risk, higher-reward exploration. We closely monitor drilling and acquisition cost trends in each of our core areas relative to product prices and, when appropriate, adjust our capital budgets accordingly and allocate funds to projects based on expected value. We do this through a disciplined and focused process that includes analyzing current economic conditions, projected rate of return on internally generated drilling inventories, and opportunities for tactical acquisitions or leasehold purchases that add substantial drilling prospects or, occasionally, provide access to new core areas that could enhance our portfolio.

Over the last five years, Apache has increasingly focused on its North American onshore resource base. Recent drilling successes and acquisitions of acreage positions across North America have built a robust drilling inventory for our Permian, Gulf Coast, and other onshore regions. We believe that this area is capable of driving our growth and performance over the next several years. As part of this strategy, we conducted a company-wide review of our portfolio and our operations in an effort to best position Apache for the long-term benefit of our shareholders. This has resulted in several key divestitures during the last eighteen months and the recent announcement and agreed sale of our Kitimat and Wheatstone LNG projects. We believe our efforts will ultimately position the Company with an established base portfolio of assets that allows for flexibility in capital allocation and provides a platform for sustainable growth. This is especially important given the volatility in oil and gas commodities.

Throughout the cycles of our industry, our focus on having a portfolio of core assets and a conservative capital structure has underpinned our long-term strategic decisions and we remain steadfast to the business principles that have guided Apache s progress since our inception. A strong sense of urgency, empowerment of our employees, effective incentive systems, and an independent mindset are at the heart of how we build value.

2015 Outlook

The rapid decline in the price of oil at the end of 2014 and into the first quarter of 2015 has been dramatic; however, we believe this environment will provide future growth opportunities for companies that have moved aggressively in response to the price drop. As we cannot predict the length or depth of this oil price correction, or the timing and extent of any potential rebound, we have moved quickly and decisively regarding what we can

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control: the timing and levels of capital spending and our cost structure. Specifically, during the third quarter of 2014 we were operating 91 rigs onshore in North America, and by the end of February 2015, our rig count was reduced to 27 rigs. We also reduced the number of completion crews and will delay completing some of our wells in backlog until the associated service costs align with the current commodity price environment. In addition to well cost initiatives, we have taken steps to reduce both lease operating and general and administrative expenses and will continue to take proactive measures to reduce them further. These actions were taken with the goal of quickly reducing well costs to a level that will enable us to generate profitable rates of return under today s depressed commodity prices environment.

We have initially set our 2015 capital budget at $3.8 billion, which is approximately 60 percent lower than the prior year, as a result of our response to the changing market conditions, operating cash flow forecasts and divested assets. Of this amount, approximately $2.1 billion to $2.3 billion is allocated for projects in North America, with the remaining amount allocated across our international regions. Our budgeted amounts exclude expenditures attributable to a one-third non-controlling interest in Egypt. While some funds have been committed for certain 2015 exploration wells and development projects, the majority of our capital activity is discretionary and subject to acceleration, deferral, or cancelation as conditions warrant. We closely monitor commodity prices, service cost levels, regulatory impacts, and numerous other industry factors and routinely adjust our budgets in response to changing market conditions and operating cash flow forecasts. With the current capital program, we are projecting our production to be relatively flat compared to 2014, when adjusting for divested assets.

Key Financial and Operating Results

Results for the year ended December 31, 2014 include:

- Daily production of oil, natural gas, and natural gas liquids averaged 647 Mboe/d during 2014. Excluding the impact of the recently divested assets in the Gulf of Mexico shelf, Canada, and South Texas, production for the year would have increased 5 percent from 2013.

- Liquids production for the year averaged 387 Mboe/d, with crude oil representing 83 percent of total liquids production. North American onshore liquids production increased 17 percent, averaging 209 Mboe/d in 2014 compared to 179 Mboe/d in 2013.

- Oil and gas production revenues totaled $13.7 billion, down $2.2 billion from $15.9 billion in 2013, reflecting the impact of divestitures and lower realized prices compared to the prior year.

- Net cash provided by continuing operating activities totaled $8.4 billion, a decrease of 13 percent compared to 2013.

- Apache reported a $5.4 billion loss attributable to common stock, or $14.06 per diluted common share, compared to income of $2.2 billion, or $5.50 per share, in 2013. Earnings for 2014 reflect the after-tax impact of oil and gas property write-downs totaling $3.1 billion, impairments totaling $2.1 billion, deferred tax adjustments totaling $2.1 billion, and a $517 million loss on discontinued operations in Argentina.

Earnings for 2013 reflect the after-tax impact of oil and gas property write-downs totaling $541 million, deferred tax adjustments totaling $197 million, and a $191 million loss on discontinued operations in Argentina.

Operational Developments

Exploration, Exploitation, and Development Activities

Our internally generated exploration and drilling opportunities provide the foundation for our growth. Highlights of our 2014 drilling successes, exploration discoveries, and other opportunities for long-term growth are discussed below. The prior-year comparisons include volumes from properties in the Gulf of Mexico and Canada that have since been divested.

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North America

North America onshore liquids averaged 208,769 barrels per day, up 17 percent over prior year production, as a direct result of our active onshore drilling activity during the year. Gas production in North America onshore was down 16 percent compared to the prior year, a function of divestiture activity.

North America onshore liquids production represented 54 percent of our worldwide liquids production and 32 percent of our overall production.

The Permian region averaged 40 operated rigs during the year, drilling 728 gross wells, 549 net wells. Drilling activity in the region resulted in a production increase of 25 percent relative to the prior year. Over half of the region s production is crude oil and 19 percent is NGLs. Combined, this represents almost a third of Apache s total liquids production for 2014.

The Central region averaged 28 operated rigs during the year, drilling 307 gross wells, 203 net wells, in plays such as the Granite Wash, Marmaton and Cleveland. The region has recently shifted its focus to the more prospective prospects in the Canyon Lime play in the Whittenburg basin, where we recently started flow back on our first four-well pad.

The Gulf Coast region averaged 9 operated rigs during the year, drilling 77 gross wells, 62 net wells. In the East Texas Eagle Ford play, the region brought on 14 new wells in the Reveille area of Brazos County where we continue to progress the play and enhance our economics by lowering well costs and refining our geological assessment. Liquids production was up 18 percent relative to the prior year.

The Canada region averaged 8 operated rigs during the year, drilling 106 gross wells, 88 net wells. Canada further established key plays in the Duvernay and Montney formations with a focus on reducing drilling and completion costs. In the Duvernay, we began drilling our first seven-well pad and expect to see test rates in the third quarter of 2015. Our Montney drilling has been focused in the Wapiti area.

International

The Egypt region continued an active drilling program for the year, averaging 27 rigs and drilling 220 gross wells, 195 net wells. Several new field discoveries were announced during the year based on successful drilling and exploration activity. These include Ptah and Berenice field discoveries in the fourth quarter, which appear to be two of Apache s largest oil field discoveries in Egypt over the last 15 years.

The North Sea region averaged 5 rigs, drilling 22 gross wells, 19 net wells. During the year, the region was able to achieve record production in the fourth quarter of 80,806 boe/d. Just as significant, the region successfully completed the regularly scheduled annual maintenance turnaround across all operated assets ahead of schedule and without incident.

The Australia region announced in August 2014 an oil discovery at the Phoenix South 1 exploration well in Australia s offshore Canning Basin. Early tests have confirmed at least four discrete oil columns in the Triassic Lower Keraudren formation. Further drilling and evaluation is planned for 2015. In addition, successful commencement of production from the Balnaves oil development occurred late in the third quarter of 2014.

The Australia region s Coniston development project is projected for first oil in the first half of 2015 upon completion of required upgrades and capacity expansion on the FPSO vessel.

Acquisition and Divestiture Activity

Over the last several years, Apache has high-graded our portfolio through strategic acquisitions and divestments. For detailed information regarding our acquisitions and divestitures, please refer to Note 2

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Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. During 2014 and 2013, Apache announced the following significant transactions:

2014 Activity

LNG Projects Divestiture In December 2014, Apache agreed to sell its interest in two LNG projects, Wheatstone LNG in Australia and Kitimat LNG in Canada, along with accompanying upstream oil and gas reserves, to Woodside Petroleum Limited for a purchase price of $2.75 billion plus recovery of Apache s net expenditure in the Wheatstone and Kitimat LNG projects between June 30, 2014, and closing. This transaction is subject to necessary government and regulatory approvals and is expected to close in the first quarter of 2015. As a result of the announced sale of these projects, the LNG facilities and associated downstream assets are classified as held for sale on Apache s consolidated balance sheet at December 31, 2014.

Anadarko Basin and Southern Louisiana Divestitures In December 2014, Apache completed the sale of non-core Anadarko basin and southern Louisiana oil and gas assets for approximately $1.3 billion in two separate transactions. In the Anadarko basin, Apache sold approximately 115,000 net acres in Wheeler County, Texas, and western Oklahoma. In southern Louisiana, Apache sold its working interest in approximately 90,000 net acres. The effective date of both of these transactions is October 1, 2014.

Gulf of Mexico Deepwater Divestiture On June 30, 2014, Apache completed the sale of non-operated interests in the Lucius and Heidelberg development projects and 11 primary term deepwater exploration blocks in the Gulf of Mexico for $1.4 billion. The effective date of the transaction was May 1, 2014.

Canada Divestiture On April 30, 2014, Apache completed the sale of primarily dry gas producing hydrocarbon assets in the Deep Basin area of western Alberta and British Columbia, Canada, for $374 million. The assets comprise 328,400 net acres in the Ojay, Noel, and Wapiti areas. Apache retained 100 percent of its working interest in horizons below the Cretaceous in the Wapiti area, including rights to the liquids-rich Montney and other deeper horizons. The effective date of the transaction was January 1, 2014.

Argentina Divestiture On March 12, 2014, Apache s subsidiaries completed the sale of all of the Company s operations in Argentina to YPF Sociedad Anónima for $800 million, subject to customary closing adjustments, plus the assumption of $52 million of bank debt as of June 30, 2013. The results of operations related to Argentina have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K.

Leasehold Acquisitions During 2014, Apache completed $1.3 billion of leasehold acquisitions, substantially increasing its drilling opportunities in key focus areas in North America including the Eagle Ford and Canyon Lime plays.

2013 Activity

Egypt Sinopec Partnership On November 14, 2013, Apache announced the completion of the sale of a one-third minority participation in its Egypt oil and gas business to Sinopec for cash consideration of $2.95 billion after customary closing adjustments. Apache will continue to operate the Egypt upstream oil and gas business.

Gulf of Mexico Shelf Divestiture On September 30, 2013, Apache completed the sale of its Gulf of Mexico Shelf operations and properties to Fieldwood, an affiliate of Riverstone Holdings. Under the terms of the agreement, Apache received cash consideration of $3.7 billion, and Fieldwood assumed $1.5 billion of discounted asset abandonment liabilities. Additionally, Apache retained 50 percent of its ownership interest in all exploration blocks and in horizons below production in developed blocks.

Canadian Divestitures In September, Apache completed sales of primarily dry gas assets for $214 million. The sale includes 621,000 gross acres (530,000 net acres) and more than 2,700 wells. Additionally in October of 2013, Apache completed two additional sales of Canadian oil and gas production properties for $112 million. The assets comprise approximately 4,000 operated and 1,300 non-operated wells.

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Kitimat LNG Project In February 2013, Apache completed a transaction with Chevron Canada Limited (Chevron Canada) under which each company became a 50 percent owner of the Kitimat LNG plant, the Pacific Trail Pipelines Limited Partnership (PTP), and 644,000 gross undeveloped acres in the Horn River and Liard basins. Apache s net proceeds from the transaction were $396 million after post-closing adjustments.

Leasehold Acquisitions During 2013, Apache completed $215 million of leasehold acquisitions in North America.

Results of Operations

Oil and Gas Revenues

Apache s oil and gas revenues by region are as follows:

	For the Year Ended December 31,					
	2014		2013		2012	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
			($ in millions)			
Total Oil Revenues:						
United States	$ 4,260	40%	$ 5,262	42%	$ 4,662	36%
Canada	537	5%	563	4%	492	4%
North America	4,797	45%	5,825	46%	5,154	40%
Egypt(3)	3,126	29%	3,528	28%	4,050	31%
Australia	712	6%	779	6%	1,218	9%
North Sea	2,117	20%	2,500	20%	2,517	20%
International(3)	5,955	55%	6,807	54%	7,785	60%
Total(1)(3)	$ 10,752	100%	$ 12,632	100%	$ 12,939	100%
Total Gas Revenues:						
United States	$ 935	40%	$ 1,096	41%	$ 1,169	40%
Canada	479	21%	587	23%	751	25%
North America	1,414	61%	1,683	64%	1,920	65%
Egypt(3)	400	17%	389	15%	504	17%
Australia	346	15%	361	14%	357	12%
North Sea	169	7%	194	7%	188	6%
International(3)	915	39%	944	36%	1,049	35%
Total(2)(3)	$ 2,329	100%	$ 2,627	100%	$ 2,969	100%
NGL Revenues:						

United States	$ 549	82%	$ 544	84%	$ 395	76%
Canada	76	12%	74	11%	79	15%
North America	625	94%	618	95%	474	91%
Egypt(3)	13	2%				
North Sea	30	4%	34	5%	46	9%
International(3)	43	6%	34	5%	46	9%
Total(3)	$ 668	100%	$ 652	100%	$ 520	100%
Total Oil and Gas Revenues:						
United States	$ 5,744	42%	$ 6,902	43%	$ 6,226	38%
Canada	1,092	8%	1,224	8%	1,322	8%
North America	6,836	50%	8,126	51%	7,548	46%
Egypt(3)	3,539	26%	3,917	25%	4,554	28%
Australia	1,058	7%	1,140	7%	1,575	9%
North Sea	2,316	17%	2,728	17%	2,751	17%
International(3)	6,913	50%	7,785	49%	8,880	54%
Total(3)	$ 13,749	100%	$ 15,911	100%	$ 16,428	100%
Discontinued Operations Argentina						
Oil Revenue	45		271		271	
Gas Revenue	39		202		224	
NGL Revenue	3		18		24	
Total	$ 87		$ 491		$ 519	

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(1) Financial derivative hedging activities decreased 2014, 2013, and 2012 oil revenues $2 million, $47 million, and $146 million, respectively.
(2) Financial derivative hedging activities increased 2014, 2013, and 2012 natural gas revenues $2 million, $31 million, and $414 million, respectively.
(3) 2014 and 2013 includes revenues attributable to a noncontrolling interest in Egypt.

Production

The following table presents production volumes by region:

	For the Year Ended December 31,				
	2014	**Increase (Decrease)**	**2013**	**Increase (Decrease)**	**2012**
Oil Volume b/d:					
United States	133,667	(9%)	146,907	10%	134,123
Canada	17,593	(1%)	17,724	12%	15,830
North America	151,260	(8%)	164,631	10%	149,953
Egypt[1][2]	87,917	(2%)	89,561	(10%)	99,756
Australia	20,529	6%	19,329	(33%)	28,884
North Sea	60,699	(5%)	63,721	0%	63,692
International	169,145	(2%)	172,611	(10%)	192,332
Total	320,405	(5%)	337,242	(1%)	342,285
Natural Gas Volume Mcf/d:					
United States	591,312	(24%)	781,335	(9%)	854,099
Canada	322,783	(35%)	497,515	(17%)	600,680
North America	914,095	(29%)	1,278,850	(12%)	1,454,779
Egypt[1][2]	370,262	4%	356,454	1%	353,738
Australia	213,983	(4%)	223,433	4%	214,013
North Sea	55,964	10%	50,961	(11%)	57,457
International	640,209	1%	630,848	1%	625,208
Total	1,554,304	(19%)	1,909,698	(8%)	2,079,987
NGL Volume b/d:					
United States	58,807	8%	54,580	63%	33,527
Canada	6,180	(8%)	6,689	7%	6,258
North America	64,987	6%	61,269	54%	39,785

Egypt	671	NM		0%	
North Sea	1,392	9%	1,272	(21%)	1,618
International	2,063	62%	1,272	(21%)	1,618
Total	67,050	7%	62,541	51%	41,403
BOE per day[3]					
United States	291,027	(12%)	331,709	7%	310,000
Canada	77,569	(28%)	107,332	(12%)	122,201
North America	368,596	(16%)	439,041	2%	432,201
Egypt[2]	150,298	1%	148,970	(6%)	158,713
Australia	56,193	(1%)	56,568	(12%)	64,552
North Sea	71,419	(3%)	73,487	(2%)	74,887
International	277,910	0%	279,025	(6%)	298,152
Total	646,506	(10%)	718,066	(2%)	730,353
Discontinued Operations Argentina					
Oil (b/d)	1,698		9,375		9,741
Gas (Mcf/d)	34,854		187,390		213,464
NGL (b/d)	317		2,102		3,008
BOE/d	7,824		42,709		48,326

(1) Gross oil production and gross natural gas production in Egypt for 2014, 2013, and 2012 were as follows:

	2014	2013	2012
Oil (b/d)	197,366	197,622	213,112
Gas (Mcf/d)	894,802	912,478	899,972
NGL (b/d)	1,901		

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(2) Includes 2014 and 2013 production volumes per day attributable to a noncontrolling interest in Egypt of:

Oil (b/d)	29,292	3,875
Gas (Mcf/d)	123,511	16,278
NGL (b/d)	224	

(3) The table shows production on a barrel of oil equivalent basis (boe) in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the price ratio between the two products.

NM Not meaningful

Pricing

The following table presents pricing information by region:

	For the Year Ended December 31,				
	2014	Increase (Decrease)	2013	Increase (Decrease)	2012
Average Oil Price Per barrel					
United States	$ 87.33	(11%)	$ 98.14	3%	$ 94.98
Canada	83.57	(4%)	87.00	2%	84.89
North America	86.89	(10%)	96.94	3%	93.91
Egypt	97.44	(10%)	107.94	(3%)	110.92
Australia	94.99	(14%)	110.42	(4%)	115.22
North Sea	95.53	(11%)	107.48	(0%)	107.97
International	96.46	(11%)	108.04	(2%)	110.59
Total(1)	91.94	(10%)	102.62	(1%)	103.29
Average Natural Gas Price Per Mcf:					
United States	$ 4.33	13%	$ 3.84	3%	$ 3.74
Canada	4.07	26%	3.23	(6%)	3.42
North America	4.24	17%	3.61		3.61
Egypt	2.96	(1%)	2.99	(23%)	3.90
Australia	4.43		4.43	(3%)	4.55
North Sea	8.29	(21%)	10.43	17%	8.95
International	3.92	(4%)	4.10	(11%)	4.59
Total(2)	4.11	9%	3.77	(3%)	3.90
Average NGL Price Per barrel					
United States	$ 25.57	(6%)	$ 27.29	(15%)	$ 32.19
Canada	33.61	10%	30.50	(12%)	34.63
North America	26.33	(5%)	27.64	(15%)	32.57
Egypt	51.80	NM		0%	
North Sea	59.42	(19%)	73.06	(5%)	77.11
International	56.94	(22%)	73.06	(5%)	77.11
Total	27.28	(4%)	28.56	(17%)	34.31

Discontinued Operations Argentina			
Oil price ($/Bbl)	$ 72.70	$ 79.05	$ 75.89
Gas price ($/Mcf)	3.04	2.96	2.87
NGL price ($/Bbl)	24.57	23.64	21.55

(1) Reflects a per-barrel decrease of $0.02, $0.37, and $1.13 in 2014, 2013, and 2012, respectively, from financial derivative hedging activities.

(2) Reflects a per-Mcf increase of $0.04 and $0.49 in 2013 and 2012, respectively, from financial derivative hedging activities.

NM Not meaningful

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Crude Oil Prices

A substantial portion of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of the Company s control. Average realized crude oil prices for 2014 were down 10 percent compared to 2013, a direct result of the sharply lower benchmark oil prices in the fourth quarter of 2014.

Continued volatility in the commodity price environment reinforces the importance of our asset portfolio. While the market price received for natural gas varies among geographic areas, crude oil tends to trade within a tighter global range. Price movements for all types and grades of crude oil generally move in the same direction. Crude oil prices realized in 2014 averaged $91.94 per barrel; however, International Dated Brent crudes and sweet crude from the U.S. Gulf Coast continue to be priced at a premium to WTI-based prices. In 2014 we realized these premium prices on approximately 55 percent of our crude oil production. Our Egypt, Australia, and North Sea regions, which collectively comprised 53 percent of our 2014 worldwide oil production, received International Dated Brent pricing with 2014 oil realizations averaging $96.46 per barrel.

Natural Gas Prices

Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions. Our primary markets include North America, Egypt, Australia, and the U.K. An overview of the market conditions in our primary gas-producing regions follows:

North America has a common market; most of our gas is sold on a monthly or daily basis at either monthly or daily market prices. Our North American regions averaged $4.24 per Mcf in 2014, up from $3.61 per Mcf in 2013.

In Egypt, our gas is sold to EGPC, primarily under an industry pricing formula indexed to Dated Brent crude oil with a maximum gas price of $2.65 per MMBtu, plus an upward adjustment for liquids content. Under a legacy oil-indexed contract, which expired at the end of 2012, there was no price cap for our gas up to 100 MMcf/d of gross production. Overall, the region averaged $2.96 per Mcf in 2014, down 1 percent from the prior year.

Australia has historically had a local market with a limited number of buyers and sellers resulting in mostly long-term, fixed-price contracts that are periodically adjusted for changes in the local consumer price index. During 2014, the region averaged $4.43 per Mcf, unchanged from 2013 pricing.

Natural gas from the North Sea Beryl field is processed through the SAGE gas plant operated by Apache. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The region averaged $8.29 per Mcf in 2014, a 21 percent decrease from an average of $10.43 per Mcf in 2013.

NGL Prices

Apache s NGL production is sold under contracts with prices at market indices based on local supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Crude Oil Revenues

2014 vs. 2013 During 2014 crude oil revenues totaled $10.8 billion, approximately 15 percent lower than the 2013 total of $12.6 billion, driven by a 10 percent decrease in average oil prices and a 5 percent decrease in worldwide production. Average daily production in 2014 was 320.4 Mb/d, with prices averaging $91.94 per barrel. Crude oil represented 78 percent of our 2014 oil and gas production revenues and 50 percent of our equivalent production, compared to 79 and 47 percent, respectively, in the prior year. Lower realized prices reduced revenues $1.3 billion, while lower production volumes reduced revenues an additional $565 million.

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Worldwide oil production from continuing operations decreased 16.8 Mb/d. However, when excluding production from the Gulf of Mexico Shelf, South Texas, and Canadian asset divestitures, oil production increased 18.2 Mb/d. This increase was driven by production growth of 20.1 Mb/d in our Permian region as a result of higher drilling and recompletion activity, partially offset by a decrease in production from the North Sea on natural decline.

2013 vs. 2012 During 2013 crude oil revenues totaled $12.6 billion, $307 million lower than the 2012 total of $12.9 billion, driven by a 1 percent decrease in worldwide production and average realized prices. Average daily production in 2013 was 337.2 Mb/d, with prices averaging $102.62 per barrel. Crude oil represented 79 percent of our 2013 oil and gas production revenues and 47 percent of our equivalent production, compared to 79 and 47 percent, respectively, in the prior year. Lower production volumes reduced revenues $224 million, while slightly lower realized prices reduced revenues an additional $83 million.

Worldwide oil production from continuing operations decreased 5.0 Mb/d, however, when excluding the Gulf of Mexico Shelf and Canadian assets that were sold during 2013, oil production increased 4.0 Mb/d, driven by growth of 23.7 Mb/d from our North American regions. Our Permian and Central regions increased production by 11.9 Mb/d and 8.6 Mb/d, respectively, as a result of higher drilling and recompletion activity. Production from our remaining property base in Canada increased 2.1 Mb/d, or 14 percent, as a result of our continued focus on liquids-rich drilling targets. These increases were partially offset by a 19.7 Mb/d decrease in production from our international regions. Oil production from Egypt decreased 10.2 Mb/d, of which 7.8 Mb/d was related production used to pay taxes and, under the terms of our production sharing contracts, has no economic impact to Apache. Australia s production decreased 9.6 Mb/d as a result of natural decline from our Pyrenees and Van Gogh fields.

Natural Gas Revenues

2014 vs. 2013 Natural gas revenues of $2.3 billion for 2014 were $298 million lower than 2013, the result of a 19 percent decrease in production volumes offset by a 9 percent increase in realized prices. Worldwide production decreased 355.4 MMcf/d, lowering revenues by $533 million. Realized prices in 2014 averaged $4.11 per Mcf, an increase of $0.34 per Mcf compared to 2013, which increased revenues by $235 million.

Worldwide gas production from continuing operations decreased 19 percent. However, excluding production from the Gulf of Mexico Shelf, South Texas, and Canadian asset divestitures, gas production increased 4.7 MMcf/d. This increase was driven by production growth of 28.0 MMcf/d in the Permian region as a result of higher drilling and recompletion activity. Egypt s net production increased 13.8 MMcf/d as a result of our successful drilling program with new wells coming on-line during 2014, and production from the North Sea increased 5 MMcf/d on stronger than expected well performance. Offsetting this increase were production decreases of 20 MMcf/d from our remaining properties in Canada, a result of a shift in our drilling and recompletion activity from dry gas to liquids-rich gas properties and 9.5 MMcf/d in Australia as a result of lower customer takes under existing contractual arrangements.

2013 vs. 2012 Natural gas revenues of $2.6 billion for 2013 were $342 million lower than 2012, the result of a 8 percent decrease in production volumes and a 3 percent decrease in realized prices. Worldwide production decreased 170.3 MMcf/d, lowering revenues by $242 million. Realized prices in 2013 averaged $3.77 per Mcf, a decrease of $0.13 per Mcf from 2012, which reduced revenues by an additional $100 million.

Worldwide gas production from continuing operations decreased 8 percent; however, excluding production from the Gulf of Mexico Shelf and Canadian assets sold during 2013, gas production declined only 2 percent, or 34 MMcf/d. Production declined 66 MMcf/d from our remaining properties in Canada, a result of a shift in our drilling and recompletion activity from dry gas to liquids-rich gas properties. Production from our U.S. Deepwater region decreased 26 MMcf/d on natural decline. These decreases were partially offset by production increases of 52.6

MMcf/d in our U.S. onshore regions resulting from drilling activity focusing on liquids-rich targets, 9.4 MMcf/d in Australia on volumes from our Macedon field discovery, which commenced operations in the third quarter, and 2.7 MMcf/d in Egypt.

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NGL Revenues

2014 vs. 2013 NGL revenues totaled $668 million in 2014, an increase of $16 million from 2013, the result of a 7 percent increase in production volumes partially offset by a 4 percent decrease in realized prices. Worldwide production from continuing operations rose 4.5 Mb/d, adding $45 million to revenues. This increase was primarily driven by drilling and recompletion activity in the U.S. Permian region. Realized prices in 2014 averaged $27.28 per Mcf barrel, a decrease of $1.28 per barrel, which reduced revenues by $29 million.

2013 vs. 2012 NGL revenues totaled $652 million in 2013, an increase of $132 million from 2012, the result of a 51 percent increase in production volumes partially offset by a 17 percent decrease in realized prices. Worldwide production from continuing operations rose 21.1 Mb/d, adding $219 million to revenues. This increase was primarily driven by drilling and recompletion activity in the U.S. Central and Permian regions. Realized prices in 2013 averaged $28.56 per Mcf barrel, a decrease of $5.75 per barrel, which reduced revenues by $87 million.

Operating Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and an equivalent unit of production (boe) basis. Our discussion may reference expenses on a boe basis, on an absolute dollar basis or both, depending on context. All 2014 and 2013 operating expenses include costs attributable to a noncontrolling interest in Egypt. Operating expenses for all periods exclude discontinued operations in Argentina.

	For the Year Ended December 31,					
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
		(In millions)			**(Per boe)**	
Depreciation, depletion and amortization:						
Oil and gas property and equipment						
Recurring	$ 4,747	$ 4,894	$ 4,593	$ 20.11	$ 18.67	$ 17.18
Additional	5,001	995	1,926	21.19	3.80	7.21
Other assets	410	400	362	1.74	1.53	1.35
Asset retirement obligation accretion	181	238	228	0.77	0.91	0.85
Lease operating costs	2,479	2,864	2,784	10.51	10.93	10.41
Gathering and transportation costs	273	288	295	1.17	1.07	1.12
Taxes other than income	678	785	818	2.87	3.00	3.06
Impairments	2,357			9.99		
General and administrative expense	434	482	515	1.84	1.84	1.92
Acquisition, divestiture, and separation costs	67	33	31	0.28	0.12	0.12
Financing costs, net	130	177	172	0.55	0.68	0.64
Total	$ 16,757	$ 11,156	$ 11,724	$ 71.02	$ 42.55	$ 43.86

Recurring Depreciation, Depletion and Amortization (DD&A)

The following table details the changes in recurring DD&A of oil and gas properties from 2012 to 2014:

	Recurring DD&A (In millions)
2012 DD&A	$ 4,593
Volume change	(57)
DD&A Rate change	358
2013 DD&A	$ 4,894
Volume change	(414)
DD&A Rate change	267
2014 DD&A	$ 4,747

2014 vs. 2013 Recurring full-cost depletion expense decreased $147 million on an absolute dollar basis: $414 million on lower volumes partially offset by an increase of $267 million from a higher average cost rate per boe. Our full-cost depletion rate increased $1.44 to $20.11 per boe reflecting increased cost for exploration and development activity over the past several years.

2013 vs. 2012 Recurring full-cost depletion expense increased $301 million on an absolute dollar basis: $358 million on rate partially offset by a decrease of $57 million from lower volumes. Our full-cost depletion rate increased $1.49 to $18.67 per boe reflecting acquisition and drilling costs that exceed our historical levels.

Additional DD&A

Under the full-cost method of accounting, the Company is required to review the carrying value of its proved oil and gas properties each quarter on a country-by-country basis. Under these rules, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, net of related tax effects and discounted 10 percent per annum and adjusted for cash flow hedges. Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

During 2014, we recorded $4.4 billion ($2.8 billion net of tax) and $589 million ($224 million net of tax) in non-cash write-downs of the carrying value of the Company s U.S. and North Sea proved oil and gas properties, respectively. If oil prices do not recover significantly from the current futures market price indication, the Company expects further write-downs of the carrying value of its oil and gas properties, which may be material to the Company s consolidated financial statements, throughout the remainder of 2015.

In 2013 we recorded non-cash write-downs of the carrying value of the Company s proved oil and gas properties totaling $995 million. The after-tax impact of these write-downs was $356 million in the U.S. and $139 million in the North Sea. During the year, the Company also exited operations in Kenya and recorded $46 million net of tax to additional DD&A related to the impairment of the carrying value of the Kenyan oil and gas property leases.

In 2012 we recorded a non-cash write-down on the carrying value of our proved oil and gas property balances in Canada of $1.9 billion ($1.4 billion net of tax). The Company also recorded $28 million of additional DD&A related to the write-off of the carrying value of our oil and gas properties in New Zealand upon exiting the country and $15 million of seismic costs incurred in countries where Apache is pursuing exploration opportunities but has not yet established a presence.

Lease Operating Expenses

Lease operating expenses (LOE) include several key components, such as direct operating costs, repair and maintenance, and workover costs.

Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as rig rates, labor, boats, helicopters, materials, and supplies. Oil, which contributed nearly half of our 2014 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

The following table identifies changes in Apache s LOE rate from 2012 to 2014:

For the Year Ended December 31, 2014	Per boe	For the Year Ended December 31, 2013	Per boe
2013 LOE	$ 10.93	2012 LOE	$ 10.41
Divestitures[1]	(0.68)	Divestitures[1]	(0.11)
FX impact	(0.12)	Power and fuel costs	0.21
Labor and overhead costs	0.20	Labor and overhead costs	0.16
Transportation	0.14	Non-operated property costs	0.14
Equipment rental	0.12	Transportation	0.14
Workover costs	0.12	Workover costs	0.08
Materials	0.12	Repairs and maintenance	0.08
Saltwater disposal	0.09	Other	0.08
Other	0.31	Other increased production	(0.26)
Other increased production	(0.72)		
2014 LOE	$ 10.51	2013 LOE	$ 10.93

[1] Per-unit impact of divestitures is shown net of associated production.

Gathering and Transportation

We generally sell oil and natural gas under two common types of agreements, both of which include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a lower relative price to reflect transportation costs to be incurred by the purchaser. In this case, we record sales at the netback price received from the purchaser. Alternatively, we sell oil or natural gas at a specific delivery point, pay our own transportation to a third-party carrier, and receive a price with no transportation deduction. In this case, we record the separate transportation cost as gathering and transportation costs.

In the U.S. and Canada we sell oil and natural gas under both types of arrangements. In the North Sea, we pay transportation charges to a third-party carrier. In Australia, oil and natural gas are sold under netback arrangements. In Egypt, our oil and natural gas production is primarily sold to EGPC under netback arrangements; however, we also export crude oil under both types of arrangements.

The following table presents gathering and transportation costs we paid directly to third-party carriers for each of the periods presented:

	For the Year Ended December 31,		
	2014	2013	2012
		(In millions)	
Canada	$ 123	$ 155	$ 163
U.S.	93	84	69

Egypt	40	42	39
North Sea	17	7	24
Total Gathering and transportation	$ 273	$ 288	$ 295

2014 vs. 2013 Gathering and transportation costs decreased $15 million from 2013. Canada s 2014 costs decreased $32 million from a decline in production primarily associated with divestitures. The U.S. costs for 2014 increased $9 million as compared to 2013 primarily as a result of increased production in the Central and Permian regions from increased drilling activity partially offset by a decrease from the Gulf of Mexico asset sales. Egypt costs were down $2 million from decreases in the world scale freight rates. North Sea costs increased $10 million on increased NGL activity and oil transportation tariffs.

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2013 vs. 2012 Gathering and transportation costs decreased $7 million from 2012. The U.S. costs for 2013 increased $15 million as compared to 2012 primarily as a result of increased production in the Permian and Central region from increased drilling activity. Egypt costs were up $3 million from increases in the world scale freight rates. North Sea costs decreased $17 million. Canada s costs decreased $8 million from a decline in activity.

Taxes Other Than Income

Taxes other than income primarily consist of U.K. Petroleum Revenue Tax (PRT), Australian Petroleum Resource Rent Tax (PRRT), severance taxes on properties onshore and in state or provincial waters off the coast of the U.S. and Australia, and ad valorem taxes on properties in the U.S. and Canada. Severance taxes are generally based on a percentage of oil and gas production revenues, while the U.K. PRT is assessed on net receipts from qualifying fields in the U.K. North Sea. Australian PRRT expense is a levy assessed on the sale of hydrocarbons derived from specific developmental areas in Australia. We are subject to a variety of other taxes including U.S. franchise taxes and various Canadian taxes, including the Freehold Mineral tax and Saskatchewan Resources surtax. The table below presents a comparison of these expenses:

	For the Year Ended December 31,		
	2014	2013	2012
		(In millions)	
Australia PRRT and U.K. PRT	$ 273	$ 382	$ 451
Severance taxes	261	249	215
Ad valorem taxes	104	113	103
Other	40	41	49
Total Taxes other than income	$ 678	$ 785	$ 818

2014 vs. 2013 Taxes other than income were $107 million lower than 2013. Australian PRRT and U.K. PRT decreased $109 million over the comparable 2013 period based on a decrease in production revenues in the North Sea from qualifying fields during the year partially offset by $96 million Australian PRRT accrued during 2014. Prior periods reflect no Australian PRRT expense as sales subject to PRRT were fully offset by credits derived from exploration and development expenditures. Severance tax increased $12 million with increased production from the Permian region offset by higher tax credits and decreased oil prices. Ad valorem taxes decreased $9 million as a result of property divestitures during 2014.

2013 vs. 2012 Taxes other than income were $33 million lower than 2012. U.K. PRT decreased $69 million over the comparable 2012 period based on a decrease in production revenues from qualifying fields during the year. Prior-year property acquisitions and higher drilling activity resulted in increases of $34 million and $10 million to severance and ad valorem tax expense, respectively.

Impairments

During the fourth quarter of 2014, the Company recorded asset impairments totaling $2.4 billion, including $1.3 billion for the impairment of goodwill, $1.0 billion for the impairment of assets held for sale, and other asset impairments. For detailed information regarding impairments, please refer to Note 1 Summary of Significant Accounting Policies and Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

General and Administrative Expenses

2014 vs. 2013 General and administrative (G&A) expenses decreased $48 million, or 10 percent, from 2013. On a per-unit basis, G&A expenses stayed flat compared to prior year as a result of lower costs offset by lower production from recent divestitures. Expenses for 2014 included a $25 million benefit from nonrecurring third party cost reimbursements in Australia.

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2013 vs. 2012 General and administrative (G&A) expenses decreased $33 million, or 6 percent, from 2012. On a per-unit basis, G&A expenses were down $0.08 to $1.84 per boe, with the benefit of lower costs partially offset by the impact of lower production.

Acquisition, Divestiture and Separation Costs

Apache recorded $67 million and $33 million of expenses during 2014 and 2013, respectively, primarily related to separation costs, investment banking fees and other costs associated with recent divestitures. In 2012, the Company recorded $31 million of expenses reflecting costs related to our acquisition of Mobil North Sea and our acquisition of Cordillera.

Financing Costs, Net

Financing costs incurred during the period comprised the following:

	For the Year Ended December 31, 2014	2013	2012
		(In millions)	
Interest expense	$ 499	$ 560	$ 501
Amortization of deferred loan costs	6	8	7
Capitalized interest	(363)	(364)	(323)
Gain on extinguishment of debt		(16)	
Interest income	(12)	(11)	(13)
Total Financing costs, net	$ 130	$ 177	$ 172

2014 vs. 2013 Net financing costs decreased $47 million from 2013. The decrease is primarily related to a $61 million decrease in interest expense as a result of lower average debt balances during 2014.

2013 vs. 2012 Net financing costs increased $5 million from 2012. The increase is primarily related to a $59 million increase in interest expense from debt issuances during 2012, partially offset by a $41 million increase in capitalized interest resulting from additional unproved property balances in the Central and Permian regions. Additionally, Apache realized a gain of $16 million related to debt extinguished during 2013.

Provision for Income Taxes

In 2014, Apache evaluated its permanent reinvestment position and determined that undistributed earnings from certain subsidiaries located in Apache s Australia, Egypt, and North Sea regions will no longer be permanently reinvested. As a result of this change in position, the Company recorded $1.7 billion of U.S. deferred income tax expense on the undistributed earnings that were previously considered permanently reinvested. In addition, the Company recorded $311 million of U.S. deferred income tax expense on foreign earnings that were distributed to the U.S. in 2014.

The 2014 provision for income taxes totaled $1.6 billion. The 2014 effective rate reflects the tax benefit from the $5.0 billion non-cash write-down in the U.S. and North Sea. The Company s rate is also impacted by the $1.7 billion of deferred income tax expense recorded in 2014 for changing our position on unremitted earnings on foreign subsidiaries and $311 million of deferred income tax expense on distributed foreign earnings. In addition, the Company had approximately $2.1 billion of impairments related to non-cash write-downs of goodwill and assets held for sale. Excluding these items and certain other adjustments, the 2014 effective tax rate would have been 41 percent.

The 2013 provision for income taxes totaled $1.9 billion. The 2013 effective rate reflects the tax benefit from the $995 million non-cash write-downs in the U.S., North Sea, and Kenya, impacts from foreign currency fluctuations and a $225 million charge related to distributed foreign earnings and other adjustments. Excluding these items, the 2013 effective tax rate would have been 42 percent.

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For additional information regarding income taxes, please refer to Note 7 Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Capital Resources and Liquidity

Operating cash flows are the Company s primary source of liquidity. We may also elect to utilize available committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the sale of nonstrategic assets for all other liquidity and capital resource needs.

Apache s operating cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Significant deterioration in commodity prices negatively impacts our revenues, earnings and cash flows, and potentially our liquidity if spending does not trend downward as well. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile and have less impact than commodity prices in the short-term.

Apache s long-term operating cash flows are dependent on reserve replacement and the level of costs required for ongoing operations. Cash investments are required to fund activity necessary to offset the inherent declines in production and proved crude oil and natural gas reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of our drilling program and our ability to add reserves at reasonable costs.

We have initially set our 2015 capital budget at $3.8 billion, which is approximately 60 percent lower than the prior year as a result of our response to the changing market conditions and operating cash flow forecasts. This budget covers planned expenditures for drilling, completions, recompletion projects, equipment upgrades, expansion of existing facilities and equipment, plugging and abandonment, seismic studies, and leasing additional acreage. We closely monitor commodity prices, service cost levels, regulatory impacts, and numerous other industry factors and routinely adjust our budgets in response to changing market conditions and operating cash flow forecasts. With the current capital program, we are projecting our production to be relatively flat compared to 2014, when adjusting for divested assets.

We believe the liquidity and capital resource alternatives available to Apache, combined with proactive measures to adjust our capital budget to reflect lower oil prices and anticipated operating cash flows, will be adequate to fund short-term and long-term operations, including our capital spending program, repayment of debt maturities, and any amount that may ultimately be paid in connection with commitments and contingencies.

For additional information, please see Part I, Items 1 and 2 Business and Properties and Part I, Item 1A Risk Factors of this Form 10-K.

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Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the years presented:

	For the Year Ended December 31, 2014	2013	2012
		(In millions)	
Sources of Cash and Cash Equivalents:			
Net cash provided by continuing operating activities	$ 8,379	$ 9,603	$ 8,281
Net cash provided by Argentina discontinued operations	788	18	
Proceeds from asset divestitures	3,092	4,405	27
Proceeds from sale of Egypt noncontrolling interest		2,948	
Commercial paper and bank loan borrowings, net	1,568		511
Fixed-rate debt borrowings			4,978
Other	49	21	
	13,876	16,995	13,797
Uses of Cash and Cash Equivalents:			
Capital expenditures[1]	$ 10,880	$ 10,802	$ 8,161
Leasehold and property acquisitions	1,492	419	3,969
Shares repurchased	1,864	997	
Dividends paid	365	360	332
Distributions to noncontrolling interest	140		
Equity investment in Yara Pilbara Holdings Pty Limited (YPHPL)			439
Commercial paper, credit facility and bank loan repayments, net		509	
Payments on fixed-rate debt		2,072	400
Net cash used by Argentina operations			66
Other	272	90	565
	15,013	15,249	13,932
Increase (decrease) in cash and cash equivalents	$ (1,137)	$ 1,746	$ (135)

(1) The table presents capital expenditures on a cash basis; therefore, the amounts differ from those discussed elsewhere in this document, which include accruals.

Net Cash Provided by Continuing Operating Activities

Operating cash flows are our primary source of capital and liquidity and are impacted, both in the short-term and the long-term, by volatile oil and natural gas prices. The factors that determine operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation (ARO) accretion, and deferred income tax expense, which affect earnings but do not affect cash flows.

Net cash provided by continuing operating activities for 2014 totaled $8.4 billion, down $1.2 billion from 2013. The decrease reflects comparative changes in working capital during the periods.

For a detailed discussion of commodity prices, production, and expenses, please see Results of Operations in this Item 7. For additional detail on the changes in operating assets and liabilities and the non-cash expenses which do not impact net cash provided by operating activities, please see the Statement of Consolidated Cash Flows in the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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Argentina Discontinued Operations

During 2014, Apache completed the sale of our Argentina operations and properties to YPF Sociedad Anónima for cash proceeds of $786 million. The results of operations related to Argentina have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K. Net cash provided by Argentina discontinued operations for the first quarter of 2014 was $2 million.

Asset Divestitures

During 2014, Apache completed the sale of non-core Anadarko basin and southern Louisiana oil and gas assets for $1.3 billion. In addition, Apache completed the sale of non-operated interests in the Lucius and Heidelberg development projects and 11 primary term deepwater exploration blocks in the Gulf of Mexico for $1.4 billion. The effective dates of these transactions were October 1, 2014 and May 1, 2014, respectively. Proceeds from the sale of other oil and gas properties totaled $470 million during the year.

During 2013, Apache completed the sale of Gulf of Mexico Shelf operations and properties for $3.7 billion. In addition, Apache completed a transaction with Chevron Canada under which each company became a 50 percent owner of the Kitimat LNG plant, the PTP, and 644,000 gross undeveloped acres in the Horn River and Liard basins. The proceeds from this transaction were $396 million. Proceeds from the sale of other oil and gas properties totaled $306 million during the year.

For information regarding our acquisitions and divestitures, please see Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Egypt Noncontrolling Interest

During 2013, Apache completed the sale of a one-third minority participation in its Egypt oil and gas business to Sinopec for $2.95 billion. Apache made cash distributions totaling $140 million to Sinopec in 2014.

Capital Expenditures

During 2014, capital spending for E&D activities totaled $9.7 billion compared to $9.6 billion in the prior year period. Apache s E&D capital spending was primarily focused on our North American onshore assets. In the Permian region we averaged 40 operated drilling rigs during the year. In our Gulf Coast region, during 2014 we increased activity on our Eagle Ford acreage in Texas.

Apache also completed leasehold and property acquisitions totaling $1.5 billion during 2014, compared with $419 million in 2013. Our 2014 acquisition investments focused on adding new leasehold positions to our North American onshore portfolio.

Apache s investment in gas gathering, transmission, and processing facilities totaled $1.2 billion during each of 2014 and 2013. Apache s 2014 GTP capital expenditures were primarily for the Wheatstone and Kitimat LNG facilities. In December of 2014, Apache announced an agreement to sell its interest in the two LNG projects. Apache will be reimbursed for its net expenditure in the projects between June 30, 2014, and closing, which is estimated to be approximately $1 billion. The transaction is expected to close in the first quarter of 2015. For more information, please see Note 2 Acquisitions and Divestitures in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Shares Repurchased

Apache s Board of Directors has authorized the purchase of up to 40 million shares of the Company s common stock. Shares may be purchased either in the open market or through privately held negotiated transactions. The Company initiated the buyback program on June 10, 2013, and since the inception of the program has repurchased a total of 32.2 million shares at an average price of $88.96. During 2014, 21.0 million shares were repurchased at an average price of $89.00. The Company is not obligated to acquire any specific number of shares.

Dividends

The Company has paid cash dividends on its common stock for 50 consecutive years through 2014. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other relevant factors. Common stock dividends paid during 2014 totaled $365 million, compared with $303 million in 2013 and $256 million in 2012. The Company paid dividends on its Series D Preferred Stock totaling $57 million and $76 million in 2013 and 2012, respectively. The preferred stock was converted to common stock in August 2013.

In the first quarter of 2014 the Board of Directors approved a 25 percent increase to $0.25 per share for the regular quarterly cash dividend on the Company s common shares. This increase first applied to the dividend on common shares payable on May 22, 2014, to stockholders of record on April 22, 2014, and subsequent dividends paid.

Liquidity

	At December 31,	
	2014	**2013**
	(In millions, except percentages)	
Cash and cash equivalents	$ 769	$ 1,906
Total debt	11,245	9,725
Equity	28,137	35,393
Available committed borrowing capacity	3,730	3,300
Floating-rate debt/total debt	14%	1%
Percent of total debt-to-capitalization	29%	22%

Cash and Cash Equivalents

At December 31, 2014, we had $769 million in cash and cash equivalents, of which $498 million of cash was held by foreign subsidiaries, and approximately $271 million was held by Apache Corporation and U.S. subsidiaries. The cash held by foreign subsidiaries is subject to additional U.S. income taxes if repatriated. The majority of the cash is invested in highly liquid, investment-grade securities with maturities of three months or less at the time of purchase.

Debt

At December 31, 2014, outstanding debt, which consisted of notes, debentures, and commercial paper, totaled $11.2 billion. We have $900 million of debt maturing in 2017, $2.1 billion maturing in 2018, and the remaining $8.2 billion maturing in years 2019 through 2096. At December 31, 2014, we had no current debt outstanding.

Available Credit Facilities

As of December 31, 2014, the Company had unsecured committed revolving syndicated bank credit facilities totaling $5.3 billion, of which $2.0 billion matures in December 2015, $1.0 billion matures in August 2016 and $2.3 billion matures in June 2018 pursuant to a one-year extension approved in May 2014 under the terms of the $2.3 billion facilities. In December 2014, the company entered into a $2.0 billion 364-day revolving credit facility which matures in December 2015. At maturity, the 364-day credit facility allows the Company to convert the outstanding revolving loans into one-year term loans by paying a term-out fee of 1 percent. Proceeds from borrowings may be used for general corporate purposes. Apache s available borrowing capacity under this facility and its other committed credit facilities support its commercial paper program, which was increased from $3.0 billion to $5.0 billion in December 2014. The facilities consist of the $2.0 billion 364-day credit facility, a $1.7 billion facility and a $1.0 billion facility in the U.S., a $300 million facility in Australia, and a $300 million facility in Canada. As of December 31, 2014, aggregate available borrowing capacity under the Company s credit facilities was $3.7 billion.

At the Company s option, the interest rate for the facilities is based on a base rate, as defined, or the London Inter-bank Offered Rate (LIBOR) plus a margin determined by the Company s senior long-term debt rating. The $1.7 billion credit facility also allows the Company to borrow under competitive auctions.

At December 31, 2014, the margin over LIBOR for committed loans was 0.925 percent on the $2.0 billion 364-day credit facility, 0.875 percent on the $1.0 billion U.S. credit facility, and 0.90 percent on each of the $1.7 billion U.S. credit facility, the $300 million Australian credit facility, and the $300 million Canadian credit facility. The Company also pays quarterly facility fees of 0.075 percent on the total amount of the $2.0 billion 364-day credit facility, 0.125 percent on the total amount of the $1.0 billion facility, and 0.10 percent on the total amount of the other three facilities. The margin over LIBOR and the facility fees vary based upon the Company s senior long-term debt rating.

The financial covenants of the credit facilities require the Company to maintain a debt-to-capitalization ratio of not greater than 60 percent at the end of any fiscal quarter. At December 31, 2014, the Company s debt-to-capitalization ratio was 29 percent.

The negative covenants include restrictions on the Company s ability to create liens and security interests on its assets, with exceptions for liens typically arising in the oil and gas industry, purchase money liens, and liens arising as a matter of law, such as tax and mechanics liens. The Company may incur liens on assets located in the U.S. and Canada of up to 5 percent of the Company s consolidated assets, or approximately $2.8 billion as of December 31, 2014. There are no restrictions on incurring liens in countries other than the U.S. and Canada. There are also restrictions on Apache s ability to merge with another entity, unless the Company is the surviving entity, and a restriction on its ability to guarantee debt of entities not within its consolidated group.

There are no clauses in the facilities that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes. The credit facility agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, the agreements allow the lenders to accelerate payments and terminate lending commitments if Apache Corporation, or any of its U.S. or Canadian subsidiaries, defaults on any direct payment obligation in excess of the stated thresholds noted in the agreements or has any unpaid, non-appealable judgment against it in excess of the stated thresholds noted in the agreements. The Company was in compliance with the terms of the credit facilities as of December 31, 2014.

There is no assurance that the financial condition of banks with lending commitments to the Company will not deteriorate. We closely monitor the ratings of the 25 banks in our bank group. Having a large bank group allows the Company to mitigate the potential impact of any bank s failure to honor its lending commitment.

Commercial Paper Program

In December 2014, the Company increased its commercial paper program from $3.0 billion to $5.0 billion. The commercial paper program generally enables Apache to borrow funds for up to 270 days at competitive interest rates. The commercial paper program is fully supported by available borrowing capacity under committed credit facilities. Our 2014 weighted-average interest rate for commercial paper was 0.31 percent. If the Company is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, the Company s committed credit facilities, which expire in 2015, 2016, and 2018, are available as a 100 percent backstop. As of December 31, 2014, the Company had $1.6 billion in commercial paper outstanding. At December 31, 2013, the Company had no commercial paper outstanding.

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Letter of Credit Collateral

Apache assumed abandonment obligations in conjunction with various North Sea acquisitions. Although not currently required, to ensure Apache s payment of these costs, Apache agreed to deliver a letter of credit to the applicable seller if the rating of Apache s senior unsecured debt is lowered by both Moody s and Standard and Poor s to ratings specified in the agreement with such seller. Apache has made arrangements with members of its bank group to provide letters of credit to cover certain abandonment obligations, if needed.

Total Debt-to-Capitalization

The Company s debt-to-capitalization ratio as of December 31, 2014, was 29 percent as compared to 22 percent at December 31, 2013. The increase in our debt-to-capitalization ratio is directly related to the draw on commercial paper during 2014 and the current year non-cash earnings charges for oil and gas property write-downs and asset impairments.

Off-Balance Sheet Arrangements

Apache enters into customary agreements in the oil and gas industry for drilling rig commitments, firm transportation agreements, and other obligations as described below in Contractual Obligations in this Item 7. Other than the off-balance sheet arrangements described herein, Apache does not have any off-balance sheet arrangements with unconsolidated entities that are reasonably likely to materially affect our liquidity or capital resource positions.

Contractual Obligations

The following table summarizes the Company s contractual obligations as of December 31, 2014. For additional information regarding these obligations, please see Note 6 Debt and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Contractual Obligations[1]	**Note Reference**	**Total**	**2015**	**2016-2017**	**2018-2019**	**2020 & Beyond**
			(In millions)			
Debt, at face value	Note 6	$ 11,301	$	$ 901	$ 2,270	$ 8,130
Interest payments	Note 6	9,751	482	947	851	7,471
Drilling rig commitments[2]	Note 8	999	382	573	44	
Purchase obligations[3]	Note 8	1,248	527	428	255	38
Firm transportation agreements[4]	Note 8	431	101	173	85	72
Office and related equipment	Note 8	343	49	98	80	116
Other operating lease obligations[5]	Note 8	469	131	221	82	35
Total Contractual Obligations		$ 24,542	$ 1,672	$ 3,341	$ 3,667	$ 15,862

(1) This table does not include the Company s liability for dismantlement, abandonment, and restoration costs of oil and gas properties or pension or postretirement benefit obligations. For additional information regarding these liabilities, please see Notes 5 and 9, respectively, in the Notes to Consolidated Financial Statements set forth in

Part IV, Item 15 of this Form 10-K.

(2) This represents minimum future expenditures for drilling rig services. Apache s expenditures for drilling rig services will exceed such minimum amounts to the extent Apache utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract. Drilling rig commitments will be reduced by $79 million upon the completion of the sale of Apache s interest in the Kitimat and Wheatstone LNG projects.

(3) Purchase obligations represent agreements to purchase goods or services that are enforceable, are legally binding, and specify all significant terms, including fixed and minimum quantities to be purchased; fixed,

minimum or variable price provisions; and the appropriate timing of the transaction. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, obtaining and processing seismic data, and contractual obligations to buy or build oil and gas plants and facilities, including LNG facilities. Of the total purchase obligations, $651 million will be relinquished upon completion of the sale of Apache s interest in the Kitimat and Wheatstone LNG projects.

(4) Firm transportation commitments will be reduced by $51 million upon completion of the sale of Apache s interest in the Kitimat and Wheatstone LNG projects.

(5) Other operating lease obligations pertain to other long-term exploration, development, and production activities. The Company has work-related commitments for oil and gas operations equipment, acreage maintenance commitments, and FPSOs, among other things. Other operating lease commitments will be reduced by $291 million upon the completion of the sale of Apache s interest in the Kitimat and Wheatstone LNG projects.

Apache is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. Apache s management feels that it has adequately reserved for its contingent obligations, including approximately $67 million for environmental remediation and approximately $8 million for various contingent legal liabilities. For a detailed discussion of the Company s environmental and legal contingencies, please see Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

The Company also had approximately $52 million accrued as of December 31, 2014, for an insurance contingency as a member of Oil Insurance Limited (OIL). This insurance co-op insures specific property, pollution liability, and other catastrophic risks of the Company. As part of its membership, the Company is contractually committed to pay a withdrawal premium if we elect to withdraw from OIL. Apache does not anticipate withdrawal from the insurance pool; however, the potential withdrawal premium is calculated annually based on past losses and the nature of our asset base.

Insurance Program

We maintain insurance policies that include coverage for physical damage to our assets, third party liability, workers compensation, employers liability, sudden and accidental pollution, and other risks. Our insurance coverage includes deductibles or retentions that must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

Our current insurance policies covering physical damage to our assets provide $1 billion in coverage per occurrence. These policies also provide sudden and accidental pollution coverage. Coverage for damage to our U.S. Gulf of Mexico assets specifically resulting from a named windstorm, however, is subject to a maximum of $250 million per named windstorm, which includes a self-insured retention of 40 percent of the losses above a $100 million deductible and is limited to an annual aggregate of $300 million.

Our current insurance policies covering general liabilities provide coverage of $660 million subject to Apache s interest. This coverage is in excess of existing policies, including, but not limited to, aircraft liability, employer s liability, and automobile liability. Our service agreements, including drilling contracts, generally indemnify Apache for injuries and death of the service provider s employees as well as subcontractors hired by the service provider.

Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and other highly rated international insurers covering its investments in Egypt. In the aggregate, these insurance policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $237.5 million sub-limit for currency inconvertibility.

In addition, the Company has a separate policy with OPIC, which, subject to policy terms and conditions, provides $300 million of coverage for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent Apache from exporting our share of production. In October 2012, the Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, announced that it was providing $150 million in reinsurance to OPIC for the remainder of the policy term. This provision of long-term reinsurance to OPIC will allow Apache to maintain the $300 million of insurance coverage through 2024.

Critical Accounting Policies and Estimates

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

Reserves Estimates

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate, and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations.

Proved undeveloped reserves include those 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. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a ceiling limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reserves are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

Apache has elected not to disclose probable and possible reserves or reserve estimates in this filing.

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Asset Retirement Obligation (ARO)

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Apache s removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms in the North Sea and Australia. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with Apache s oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Income Taxes

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions worldwide. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

The Company regularly assesses and, if required, establishes accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions in countries where the Company operates. Tax reserves have been established and include any related interest, despite the belief by the Company that certain tax positions meet certain legislative, judicial, and regulatory requirements. These reserves are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, case law, and any new legislation. The Company believes that the reserves established are adequate in relation to the potential for any additional tax assessments.

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill.

The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company s assets and liabilities and tax-related carryforwards at the merger date, although such estimates may change in the future as additional information becomes known. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed relative to the total acquisition cost.

In estimating the fair values of assets acquired and liabilities assumed, we made various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves as described above in Reserve Estimates of this Item 7. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future.

Goodwill

As of December 31, 2014, the Company s consolidated balance sheet included $87 million of goodwill, all of which has been assigned to the Egypt reporting unit. Goodwill is assessed at least annually for impairment at the reporting unit level. We conduct a qualitative goodwill impairment assessment as of July 1st of each year by examining relevant events and circumstances which could have a negative impact on our goodwill such as macroeconomic conditions, industry and market conditions, cost factors that have a negative effect on earnings and cash flows, overall financial performance, acquisitions and divestitures, and other relevant entity-specific events.

The first step of the impairment test requires management to make estimates regarding the fair value of each reporting unit to which goodwill has been assigned. If it is necessary to determine the fair value of the reporting unit, we use a combination of the income approach and the market approach.

Under the income approach, the fair value of each reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, the success of future exploration for and development of unproved reserves, discount rates, and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods.

Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative, and capital costs adjusted for inflation. We discount the resulting future cash flows using discount rates similar to those used by the Company in the valuation of acquisitions and divestitures.

To assess the reasonableness of our fair value estimate, we use a market approach to compare the fair value to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments about the selection of comparable companies, recent comparable asset transactions, and transaction premiums. Associated market multiples are applied to various financial metrics of the reporting unit to estimate fair value.

Although we base the fair value estimate of each reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. In the event of a prolonged global recession, commodity prices may stay depressed or decline further, thereby causing the fair value of the reporting unit to decline, which could result in an impairment of goodwill.

During the fourth quarter of 2014, the Company recognized non-cash impairments of the entire amount of recorded goodwill in the U.S., North Sea, and Canada reporting units of $1.0 billion, $163 million, and $103 million, respectively.

ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil, gas, and NGL prices, interest rates, or foreign currency and adverse governmental actions. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Risk

The Company s revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas and NGLs, which have historically been very volatile because of unpredictable events such as economic growth or retraction, weather and political climate. In 2014, our average crude oil realizations decreased to $91.94 per barrel compared to $102.62 per barrel in 2013. Our average natural gas price realizations increased 9 percent in 2014 to $4.11 per Mcf from $3.77 per Mcf in 2013.

We periodically enter into derivative positions on a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to manage fluctuations in cash flows resulting from changes in commodity prices. Apache typically uses futures contracts, swaps, and options to mitigate commodity price risk. In 2014 approximately 9 percent of our natural gas production from continuing operations and approximately 39 percent of our crude oil production from continuing operations was subject to financial derivative hedges, compared with 9 percent and 43 percent, respectively, in 2013.

On December 31, 2014, the Company did not have any open derivative positions. See Note 3 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Interest Rate Risk

The Company considers its interest rate risk exposure to be minimal as a result of fixing interest rates on approximately 86 percent of the Company s debt. At December 31, 2014, total debt included $1.6 billion of floating-rate debt. As a result, Apache s annual interest costs in 2015 will fluctuate based on short-term interest rates on approximately 14.0 percent of our total debt outstanding at December 31, 2014. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $1 million.

Foreign Currency Risk

The Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. In Australia, oil production is sold under U.S. dollar contracts, and gas production is sold under a mixture of fixed-price U.S. dollar and Australian dollar contracts. Approximately 40 percent of the costs incurred for Australian operations are paid in U.S. dollars. In Canada, oil and gas prices and costs, such as equipment rentals and services, are generally denominated in Canadian dollars but are heavily influenced by U.S. markets. Our North Sea production is sold under U.S. dollar contracts, and the majority of costs incurred are paid in British pounds. In Egypt, all oil and gas production is sold under U.S. dollar contracts, and the majority of the costs incurred are denominated in U.S. dollars. Revenue and disbursement transactions denominated in Australian dollars, Canadian dollars, and British pounds are converted to U.S. dollar equivalents based on the average exchange rates during the period.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of Other under Revenues and Other or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company s provision for income tax expense on the statement of consolidated operations. A 10 percent strengthening or weakening of the Australian dollar, Canadian dollar, and British pound against the U.S. dollar as of December 31, 2014, would result in a foreign currency net loss or gain, respectively, of approximately $135 million.

Forward-Looking Statements and Risk

This report 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 included or incorporated by reference i