APACHE CORP
Form 10-K
February 28, 2014
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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, 2013

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**
Preferred Stock Purchase Rights	**New York Stock Exchange and Chicago Stock Exchange**
Apache Finance Canada Corporation 7.75% Notes Due 2029 Irrevocably and Unconditionally Guaranteed by Apache Corporation	**New York Stock Exchange**

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, 2013	$ 32,641,836,810
Number of shares of registrant s common stock outstanding as of January 31, 2014	394,724,983

Documents Incorporated By Reference

Portions of registrant s proxy statement relating to registrant s 2014 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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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.

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.

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.

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 six countries: the U.S., Canada, Egypt, Australia, the U.K. North Sea (North Sea), and Argentina. 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 5, 2013, 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.

Growth 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. Apache s long-term perspective has many dimensions, which are centered on the following core strategic components:

- diverse portfolio of core assets
- conservative capital structure
- rate of return focus

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Throughout the cycles of our industry, these strategies have 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 28 years and production 32 out of the past 35 years, a testament to our consistency over the long-term.

Apache pursues growth opportunities through exploration and development drilling, supplemented by occasional strategic acquisitions and portfolio highgrading through asset divestitures. At the end of 2012 and the beginning of 2013, Apache undertook a strategic review of our portfolio with the ultimate goal of keeping the right mix of assets that generate strong returns and excess cash flow and drive more predictable production growth to create shareholder value. In May 2013, Apache announced that it would divest approximately $4 billion in assets and use the proceeds to pay down debt and repurchase Apache common shares. Apache surpassed these goals, divesting approximately $7 billion of assets, paying down $2.6 billion in debt, and repurchasing $1 billion in Apache common shares during 2013. Significant transactions since announcing our strategic repositioning initiatives include:

Argentina Divestiture On February 12, 2014, Apache subsidiaries announced an agreement to sell all of its operations in Argentina to YPF Sociedad Anónima (YPF) for cash consideration of $800 million plus the assumption of $52 million of bank debt. The transaction is expected to close in the first quarter of 2014.

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 Divestiture 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.

Canadian Divestitures In the third and fourth quarters of 2013, Apache completed three separate divestitures of oil and gas producing properties in Canada for total cash consideration of $326 million before customary post-closing adjustments.

Our growth portfolio going forward will be centered on (i) increasing onshore North American liquids production that provides for more predictable and attractive rates of return, (ii) generating excess cash flow from our international operations, and (iii) continuing longer-term growth initiatives, which include our Wheatstone and Kitimat LNG projects. In 2013, we demonstrated the effectiveness of our transition towards North American Onshore liquids growth, with all four of our onshore North American regions increasing liquids production and by replacing more than our worldwide production through our exploration and development activities.

For a more in-depth discussion of our growth strategy, 2013 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.

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Geographic Area Overviews

During 2013, 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.

The following table sets out a brief comparative summary of certain key 2013 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	121.1	44%	$ 6,902	1,347	51%	1,179	1,148
Canada	39.2	14	1,224	462	17	143	135
Total North America	160.3	58	8,126	1,809	68	1,322	1,283
Egypt[1]	54.4	19	3,917	271	10	210	181
Australia	20.6	7	1,140	326	12	12	11
North Sea	26.8	10	2,728	150	6	19	17
Argentina	15.6	6	491	90	4	28	28
Total International	117.4	42	8,276	837	32	269	237
Total	277.7	100%	$ 16,402	2,646	100%	1,591	1,520

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

North America

Apache s North American asset base primarily comprises operations in the Permian Basin, the Anadarko basin in western Oklahoma and the Texas Panhandle, Gulf Coast onshore and offshore 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 has acquired significant acreage positions in many attractive basins and plays across North America. This extensive portfolio expansion phase shifted during 2013 when we completed strategic divestitures to rebalance our portfolio to an asset mix that we believe will continue to generate strong returns, 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 had liquids growth of 34 percent during 2013, primarily in the Permian Basin and Anadarko basin.

North America contributed approximately 58 percent of our worldwide production and 50 percent of our oil and gas production revenues for the year. At year-end 2013, North America held 68 percent of our estimated worldwide proved reserves including noncontrolling interests in Egypt.

United States

Overview We have access to significant liquid hydrocarbons across our 11.5 million gross acres in the U.S., approximately 75 percent of which is undeveloped. In 2013, 61 percent of our U.S. production and 67 percent of our U.S. year-end reserves were oil and natural gas liquids. Approximately 44 percent of Apache s worldwide equivalent 2013 production and 51 percent of our estimated proved reserves were in the U.S. To better control our development efforts across broad acreage positions within the U.S., during 2013 our assets were divided into five regions: Permian, Central, Gulf Coast Onshore, Gulf of Mexico Deepwater, and the Gulf of Mexico Shelf. In 2014, the Gulf of Mexico Shelf region and Gulf of Mexico Deepwater region have been combined into the Gulf of Mexico region.

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Permian Region Our Permian region controls over 3.3 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 13,500 producing wells in 155 fields, including 47 waterfloods and seven CO^2 floods. Total region production for 2013 was up over 17 percent sequentially as a result of an active drilling program where we ran an average of 42 rigs during the year. Production in the region has increased for 12 consecutive quarters. During the year, we drilled or participated in drilling 785 wells, of which 186 were horizontal. The Permian region s year-end 2013 estimated proved reserves were 910 MMboe, representing 14 percent growth over year-end 2012.

A key focus area of our activity during the year continued to be the multi-zone development of the Deadwood area. Deadwood is the most active of our plays in the Midland basin where we ran an average of nearly 10 rigs and drilled 189 wells. Our activity in the Deadwood area is primarily drilling vertical wells targeting the Wolfwood and the Fusselman zones.

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. Our success has led the region to increase the number of horizontal drilling rigs being utilized throughout 2013, and now approximately half of our rigs are drilling horizontal wells. In 2013, we ramped up multi-rig development programs in several horizontal plays in the Midland basin, targeting the Wolfcamp and Cline Shales. We have also increased development activity in our Yeso area of New Mexico and across the Permian s Central Basin Platform. These extensive programs will carry into 2014 and drive the region s growth.

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. For 2014, the Permian region plans to invest approximately $2.55 billion. The region s capital program 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.

Central Region The Central region controls 1.8 million gross acres that are mostly held-by-production and includes more than 3,800 producing wells primarily in western Oklahoma and the Texas Panhandle. The region was Apache s first core area and has historically grown through low-risk, highly predictable exploitation. Over the last several years, the region has aggressively targeted oil and liquids-rich gas plays through horizontal drilling across its acreage holdings. Oil and liquids production expanded during 2013, with oil production growth of 61 percent and NGL production more than doubling compared to the prior year. Total region production in 2013 was 91 Mboe/d, of which 50 percent was oil and natural gas liquids. As of year-end, the Central region s estimated proved reserves totaled 304 MMboe, an increase of nearly 14 percent from year-end 2012.

The primary factor driving the region s growth in 2013 was an active drilling program where we ran an average of 24 rigs during the year, over a 30 percent increase from the prior year. We drilled or participated in drilling 322 wells during 2013, with 98 percent being completed as producers.

The vast majority of our drilling activity has been in the Anadarko basin, which consists of a series of thick, stacked formations of liquids-rich, low-permeability sandstones. The Company s significant acreage position in the basin provides a robust drilling inventory for the next several years across numerous horizontal liquids plays, notably the Granite Wash, Tonkawa, Marmaton, Cottage Grove, and Cleveland. In addition, in 2013 the region continued to invest in infrastructure facilities and contractually secure takeaway capacity.

In addition, in 2011 Apache acquired 92,000 contiguous net acres in the Whittenburg basin, located approximately 70 miles west of our Anadarko basin properties. The region has operated two drilling rigs targeting vertical objectives in 2012 and 2013, completing 26 vertical wells into the Canyon Wash sand and achieving a peak production rate of 10 Mb/d and 16 MMcf/d. Apache has now turned its attention to the prolific Canyon lime and is currently drilling its first horizontal test.

The Central region plans to run an average of 34 rigs during 2014 and invest approximately $1.75 billion for drilling, recompletions, equipment upgrades, and production enhancement projects.

Gulf Coast Regions Our Gulf Coast assets are primarily located in and along the Gulf of Mexico, in the areas onshore and offshore Texas, Louisiana, Alabama, and Mississippi. During 2013 the area was divided into three regions, which include the Gulf Coast Onshore, Gulf of Mexico Deepwater, and Gulf of Mexico Shelf. In 2014, the Gulf of Mexico Shelf region and Gulf of Mexico Deepwater region have been combined into the Gulf of Mexico region.

Apache s Gulf Coast Onshore region is known for its proven onshore and near-shore basins of Texas, Louisiana and Mississippi where it has a significant acreage position of approximately 1.3 million gross acres, including approximately 275,000 mineral fee acres. During the year, the region primarily drilled shallow and moderate-depth development wells and completed the construction of gathering and processing facilities in our Atchafalaya Bay development project. The region also continued evaluating deeper exploitation opportunities and several unconventional resource plays, which included drilling three Eagle Ford shale wells on our Southeast Texas acreage with plans to substantially increase activity in 2014. For the year, the region drilled or participated in drilling 43 wells and projects drilling approximately 90 wells in 2014.

In offshore waters greater than 500 feet deep, the Gulf of Mexico Deepwater region is a relatively underexplored and oil-prone area that provides exposure to significant reserve and production potential. The Company owns over 900,000 gross acres across nearly 170 blocks as of the end of 2013. The Deepwater region contributed approximately two percent of Apache s worldwide production with multiple projects and developments underway. The non-operated Lucius project, where Apache holds an 11.7 percent working interest, is currently under development with first production projected by year-end 2014. In addition, the large scale non-operated Heidelberg project was sanctioned in late 2012. Apache has a 12.5 percent working interest in this development with first production projected for 2016.

Apache s former Gulf of Mexico Shelf region, constituting Gulf assets in waters less than 500 feet deep, experienced a significant shift during 2013 as the region s producing base and associated infrastructure was sold to Fieldwood in September. As part of the transaction, Apache retained 50 percent of its ownership interest in all exploration blocks and in horizons below production in developed blocks, and access to existing infrastructure. These retained interests cover approximately 2.5 million gross acres across 515 offshore blocks. Several wells are expected to be drilled during 2014, and we expect future activities to provide a platform for continued exploration growth in this basin. Total region production in 2013 was 71 Mboe/d, reflecting nine months of Shelf production prior to the divestiture.

In 2014, Apache plans to invest approximately $550 million and $450 million in its Gulf Coast (formerly Gulf Coast Onshore) and Gulf of Mexico regions, respectively. The capital will be spent on drilling, recompletion, and development projects, equipment upgrades, production enhancement projects, seismic acquisitions, additional leasing activity, and plugging and abandonment of wells and platforms.

U.S. Marketing In general, most of our U.S. 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.

Apache primarily markets its U.S. 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. The 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.

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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.

Canada

Overview Apache entered the Canadian market in 1995 and currently holds nearly 5.4 million gross acres across the provinces of British Columbia, Alberta, and Saskatchewan. The region s large acreage position provides portfolio diversification as well as significant drilling opportunities. Our Canadian region provided approximately 14 percent of Apache s 2013 worldwide production.

In 2013, Apache drilled or participated in drilling 143 wells in Canada, with a continued focus on increasing oil and liquids-rich gas production. Reservoir modeling and horizontal drilling technology advanced several oil and liquids-rich gas plays in the Montney, Swan Hills, Viking, Bluesky, and Glauconite formations. Success with multi-stage fracture completions continues to increase the scope of oil and liquids-rich gas drilling opportunities.

We also furthered our region s shift toward an oil and liquids-rich gas asset portfolio through several strategic divestitures of primarily dry gas assets during 2013. In September we completed the sale of certain Alberta producing assets for approximately $214 million. The assets comprised 621,000 gross acres (530,000 net acres) and more than 2,700 wells in the Nevis, North Grant Lands, and South Grant Lands areas. In October 2013, we completed two additional sales of producing properties in Saskatchewan and Alberta for $112 million. The divested assets comprised approximately 4,000 operated and 1,300 non-operated wells, including our Hatton, St. Lina, Marten Hills, Snipe Lake, and Valhalla developments, as well as a portion of our Hawkeye producing properties. Combined, our 2013 divestitures totaled 13 percent of the region s production.

The Kitimat LNG project will allow us to monetize large unconventional natural gas resources in the Liard and Horn River basins in northern British Columbia. 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. Chevron Canada will operate the LNG plant and pipeline while Apache Canada will continue to operate the upstream assets. The Kitimat plant has received all significant environmental approvals and a 20-year export license from the Canadian federal government. Although the project has not reached a final investment decision, we believe Chevron s experience in developing LNG projects and marketing expertise will assist in moving the development forward. In 2014, we plan to invest approximately $1.0 billion of capital in the Kitimat project, which includes the LNG plant as well as our upstream assets in the Horn River and Liard basins. With a 50 percent project participation, Apache is actively evaluating ways to right-size its level of participation in the Kitimat LNG project.

Additionally, the region plans to invest approximately $600 million in drilling and development projects, equipment upgrades, and production enhancement projects for our other upstream assets.

Marketing Our Canadian natural gas marketing activities focus on sales to utilities, end-users, integrated major oil companies, supply aggregators, and marketers. We maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk in our portfolio. To diversify our market exposure, we transport natural gas under firm transportation contracts to delivery points into the United States. We sell the majority of our Canadian gas on a monthly basis at either first-of-the-month or daily AECO index 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.

Canadian crude oil production is sold to integrated major companies, refiners, and marketing companies based on a WTI price, adjusted for quality, transportation, and a market-reflective differential. 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.

The region 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, offshore the U.K. in the North Sea, and Argentina. In 2013, international assets contributed 42 percent of our production and 50 percent of our oil and gas revenues. At year-end 2013, 32 percent of our estimated proved reserves 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, we held 9.8 million gross acres, with gross oil production of 198 Mb/d and gross natural gas production of 912 MMcf/d in 2013, or 90 Mb/d and 356 MMcf/d net to Apache s consolidated holdings. Although 3.0 million gross undeveloped acres expired in January 2014, we continue to pursue longer term extensions on areas we believe provide attractive growth opportunities. Of our remaining acreage, 72 percent is undeveloped, providing us with considerable exploration and development opportunities for the future.

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. In 2013 Apache was granted 20 new development leases, representing one of our most successful years since our entry into Egypt.

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. During 2013, we drilled 181 development and injection wells and 54 exploration wells. Approximately 60 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.

Apache has also made a strategic decision to advance the application of horizontal drilling technology to unlock new plays in Egypt. During the year, we drilled our first well of a multi-well horizontal drilling program in the Abu Gharadig field. During December, this well produced an average of 1,681 b/d and 3 MMcf/d from a 1,970 foot lateral. This well was one of eight horizontal wells initiated during 2013 to test the technology s ability to increase recoveries in a variety of conventional and unconventional reservoirs. Additional horizontal drilling is planned in the Abu Gharadig and surrounding fields in 2014.

In November 2013, Apache announced the completion of the sale of a one-third minority interest in its Egypt oil and gas business to Sinopec. After customary closing adjustments, Apache received cash consideration of $2.95 billion. At year-end 2013, our Egypt region s estimated proved reserves were 271 MMboe, of which 90

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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.

Heading into 2014, the region will continue an active drilling program and plans to invest approximately $1.4 billion, including approximately $460 million attributable to Sinopec s noncontrolling interest, for drilling, recompletion projects, development projects, and seismic acquisition.

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 $2.99 per Mcf in 2013.

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 presently sold to EGPC is sold on a spot basis priced at Brent with a monthly EGPC official differential applied.

Egypt political unrest In February 2011, former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power, announcing that it would remain in power until presidential and parliamentary elections could be held. In June 2012, President Mohamed Morsi of the Muslim Brotherhood s Freedom and Justice Party was elected as Egypt s new president.

In July 2013, the Egyptian military removed President Morsi from power and installed Egypt s Chief Justice, Adly Mansour, as acting president of a temporary government, which announced that it would seek to schedule parliamentary and presidential elections in early to mid-2014. In January 2014, Egyptians voted on and overwhelmingly approved a new constitution, and Mr. Mansour announced that the presidential election will be held prior to the parliamentary elections. While the date of the presidential election has not been announced, it is expected to be held by mid-April 2014.

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 could materially and adversely affect our business, financial condition, and results of operations.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and other highly rated international insurers covering a portion of its investments in Egypt. In the aggregate, these insurance policies, subject to the policy terms and conditions, provide approximately $856 million of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $149 million sub-limit for currency inconvertibility.

In addition, Apache has a separate policy with OPIC, which 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.

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

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operated in the Carnarvon basin since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993. In total, we control approximately 7.9 million gross acres offshore Western Australia through 30 exploration permits, 18 production licenses, and 9 retention leases. Approximately 89 percent of our acreage is undeveloped, and the region continues to actively pursue additional acreage opportunities.

During 2013, the region had net production of 19 Mb/d and 223 MMcf/d, contributing 7 percent of Apache s worldwide consolidated production revenue, 7 percent of worldwide consolidated production and 12 percent of year-end consolidated proved reserves. Production compared to the prior year was 12 percent lower primarily as a result of natural decline in the Pyrenees and Van Gogh oil fields.

Partially offsetting production declines from Pyrenees and Van Gogh was production through the BHP Billiton-operated Macedon gas plant, which commenced operations in the third quarter of 2013. The $1.5 billion natural gas facility, Western Australia s fourth domestic gas hub, has a production capacity of approximately 200 MMcf/d. Gas is delivered to the facility via a 60-mile pipeline from four completed subsea gas wells in the Macedon field. Apache has successfully marketed production in the Macedon field under long-term contracts at prices higher than historical realizations. We have a 28.57 percent non-operating working interest in the field and gas plant. Apache has a participating interest in three of the four domestic gas hubs in Australia.

The region participated in drilling 12 offshore wells during 2013, of which 4 were exploration or appraisal wells, compared to 15 wells drilled in 2012. 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.

Development of the Coniston oil field project, which lies just north of the Van Gogh field, continued toward projected first production in 2014. The field will be produced via subsea completions tied back to the Ningaloo Vision Floating Production Storage and Offloading Vessel (FPSO) at Van Gogh. Required modifications to the FPSO and the final phase of subsea installation work is planned for the first half of 2014. Apache has a 52.5 percent working interest in the field.

The region also continued development of the Balnaves field, an oil discovery located near the Brunello gas field. Development well drilling commenced in the third quarter of 2013, and the project is expected to begin production by the third quarter of 2014 utilizing a leased FPSO vessel. Apache has a 65 percent working interest in the project.

In 2013, further advances were made on the region s largest development effort, which is the Chevron-operated Wheatstone LNG project (Wheatstone). The first phase of the Wheatstone project will comprise two LNG processing trains with a combined capacity of approximately 8.9 million metric tons per annum (mtpa), a domestic gas plant, and associated infrastructure. Apache has a 13 percent interest in the project and expects to invest approximately $4 billion over five years for the field and LNG facility development. Apache will supply gas to Wheatstone from its operated Julimar and Brunello complex. The 65 percent interest in the Julimar development project is expected to generate average net sales to Apache of approximately 140 MMcf/d of gas (equivalent to 1.07 million mtpa of LNG) at prices pegged to world oil markets, 22 MMcf/d of sales gas into the domestic market, and 3,250 barrels of condensate per day. First production is projected for the end of 2016.

These development projects require significant capital investments above those for traditional drilling programs. During 2014, the region plans to invest approximately $800 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition. Approximately $1.4 billion of additional 2014 capital will be invested in the Wheatstone development project.

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, 2013, Apache had 21 active gas contracts in Australia with expiration dates ranging from August 2014 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 are substantially 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 sales well above crude sold at WTI-based prices.

During 2013 Apache finalized binding Sales and Purchase Agreements with two Asian customers for the delivery of approximately 25 percent of Apache s net LNG offtake from Wheatstone.

North Sea

Overview Apache entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (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, Apache in 2012 acquired Mobil North Sea Limited (Mobil North Sea), 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, Scott, and Telford fields. In total, Apache has interests in approximately 1.2 million gross acres in the U.K. North Sea.

In 2013, the North Sea region produced 65 Mb/d and 51 MMcf/d, contributing 17 percent of Apache s worldwide consolidated production revenue, 10 percent of worldwide consolidated production, and 6 percent of year-end consolidated proved reserves. During the year we drilled 19 wells in the North Sea, of which 17 were productive. Apache s drilling success was highlighted with discoveries in the Tonto oil field. The Tonto-1 well, completed in April, had initial production of 10.3 Mb/d, and the Tonto-2 well, completed in September, had initial production of 8.3 Mb/d. Apache has a 100 percent working interest in the wells. The Tonto discovery follows Maule and Bacchus as the third new field brought online by Apache in the Forties area over the last three years. All three fields qualify for the U.K. s small field allowance, which provides economic incentives for operators to bring discoveries from small fields into production. During the fourth quarter the region continued to commission the Forties Alpha Satellite Platform, adjacent to the main Forties Alpha platform. This platform has been constructed to exploit new opportunities at Forties and provides an additional 18 drilling slots as well as power generation, fluid separation, and gas lift compression.

In 2014, the region plans to invest approximately $900 million on drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition, focusing on both the Beryl field and Forties area.

Marketing We have traditionally sold our North Sea crude oil under both term contracts and spot cargoes. The Forties 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 Beryl spot cargoes are market driven and can trade at a premium 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 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

Overview We have had a continuous presence in Argentina since 2001 and have grown our holdings in the region through an active drilling program and targeted acquisitions. The region has active operations in the provinces of Neuquén, Rio Negro, and Tierra del Fuego. As of year-end 2013, Apache held interests in 31 concessions, exploration permits, and other interests totaling 3.3 million gross acres in three of the main Argentine hydrocarbon basins: Neuquén, Austral, and Cuyo. These concessions have varying expiration dates ranging from one year to over 15 years remaining, subject to potential extensions. In 2013, Argentina produced 6 percent of our worldwide consolidated production and held 4 percent of our year-end consolidated proved reserves.

On February 12, 2014, Apache announced an agreement to sell all of its operations in Argentina to YPF for cash consideration of $800 million plus the assumption of $52 million of bank debt as of June 30, 2013. The transaction is expected to close in the first quarter of 2014.

Marketing

Natural Gas Apache sells its natural gas in Argentina through three different pricing structures:

Gas Plus Program: This program was instituted by the Argentine government in 2008 to encourage investments for new gas supplies through the development of conventional and unconventional (tight sands) reserves. Under this program, Apache is allowed to sell gas from qualifying projects at prices that are above the regulated rates. During 2013, the average Gas Plus volume sold by Apache was 79.9 MMcf/d at an average price of $4.90 per Mcf.

Government-regulated pricing: The volumes we are required to sell at regulated prices are set by the Argentine government and vary based on seasonal factors and category. During 2013, we realized an average price of $0.78 per Mcf on government-regulated sales.

Unregulated market: In 2013, realizations on sales in the unregulated market averaged $3.69 per Mcf.

In 2013, we realized an average price of $2.96 per Mcf in the region.

Crude Oil The crude oil in Argentina is subject to an export tax which effectively limits the prices buyers are willing to pay for domestic sales. In 2013 there was an increase on the price of the crude paid by refiners, a combination of an increase of the sales price of fuels to end-users and the decrease of domestic production. Apache´s average sales price in Argentina during 2013 was $79.05 per barrel.

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, high-reward exploration opportunities located in frontier basins as well as new plays in more mature basins. During 2014, we plan to invest approximately $75 million to further several projects and continue pursuing additional exploration opportunities.

Major Customers

In 2013, 2012, and 2011 purchases by Royal Dutch Shell plc and its subsidiaries accounted for 24 percent, 20 percent, and 11 percent, respectively, of the Company s worldwide oil and gas production revenues. In 2011, purchases by the Vitol Group accounted for 13 percent of the Company s worldwide oil and gas production revenues.

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Drilling Statistics

Worldwide in 2013 we participated in drilling 1,591 gross wells, with 1,520 (96 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: 160 in the U.S. (115.4 net); 17 in Egypt (17.0 net); and 2 in Argentina (0.3 net).

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**
2013									
United States	15.6	11.2	26.8	834.9	12.6	847.5	850.5	23.8	874.3
Canada	0.0	0.0	0.0	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	0.0	3.4	5.6	0.4	6.0
North Sea	0.0	0.5	0.5	13.4	0.1	13.5	13.4	0.6	14.0
Argentina	2.4	0.0	2.4	22.0	0.0	22.0	24.4	0.0	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	0.0	1.3	11.7	3.9	15.6	13.0	3.9	16.9
Argentina	2.0	0.0	2.0	23.0	0.0	23.0	25.0	0.0	25.0
Other International	0.0	0.5	0.5	0.0	0.0	0.0	0.0	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
2011									
United States	12.4	5.0	17.4	522.0	17.0	539.0	534.4	22.0	556.4
Canada	4.0	5.0	9.0	77.2	5.0	82.2	81.2	10.0	91.2
Egypt	28.2	19.8	48.0	112.6	6.0	118.6	140.8	25.8	166.6
Australia	1.0	2.3	3.3	1.0	0.0	1.0	2.0	2.3	4.3
North Sea	0.0	0.3	0.3	10.7	1.9	12.6	10.7	2.2	12.9
Argentina	4.0	1.0	5.0	29.4	0.3	29.7	33.4	1.3	34.7
Total	49.6	33.4	83.0	752.9	30.2	783.1	802.5	63.6	866.1

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, 2013, is set forth below:

	Oil		Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	14,164	9,346	5,001	2,831	19,165	12,177
Canada	2,000	939	3,030	2,277	5,030	3,216
Egypt	1,040	992	85	80	1,125	1,072
Australia	49	23	16	9	65	32
North Sea	161	104	24	14	185	118
Argentina	475	396	425	389	900	785
Total	17,889	11,800	8,581	5,600	26,470	17,400

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Gross natural gas and crude oil wells include 650 wells with multiple completions.

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 Sales Price		
Year Ended December 31,	**Oil (MMbbls)**	**NGLs (MMbbls)**	**Gas (Bcf)**	**Average Lease Operating Cost per Boe**	**Oil (Per bbl)**	**NGLs (Per bbl)**	**Gas (Per Mcf)**
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
Argentina	3.4	0.8	68.4	12.89	79.05	23.64	2.96
Total	126.5	23.6	765.4	12.06	101.99	28.40	3.70
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
Argentina	3.5	1.1	78.1	10.85	75.89	21.55	2.87
Total	128.8	16.3	839.4	11.49	102.53	33.45	3.80
2011							
United States	43.6	8.1	315.6	$ 11.80	$ 95.51	$ 48.42	$ 4.91
Canada	5.2	2.2	230.9	13.86	93.19	45.72	4.47
Egypt	37.9		133.4	7.19	109.92		4.66
Australia	14.0		67.6	7.80	111.22		2.69
North Sea	19.9		0.8	11.61	104.09		22.25
Argentina	3.5	1.1	77.5	9.83	68.02	27.90	2.64
Total	124.1	11.4	825.8	10.62	102.19	45.95	4.37

(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, 2013, in each country where we have operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)			
United States	8,730	4,772	2,797	1,445
Canada	2,329	1,712	3,078	2,151
Egypt	7,852	5,060	1,971	1,806
Australia	7,003	3,849	900	545
North Sea	1,092	487	160	98
Argentina	3,037	2,247	231	198
Total	30,043	18,127	9,137	6,243

As of December 31, 2013, Apache had 3.2 million net undeveloped acres scheduled to expire by year-end 2014 if production is not established or we take no other action to extend the terms. Additionally, Apache has 2.7 million and 1.9 million net undeveloped acres set to expire in 2015 and 2016, 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 1.5 million net acres in Egypt scheduled to expire in 2014, and 1.0 million and 0.9 million net undeveloped acres set to expire in 2015 and 2016, respectively. Nearly all of the acreage expiring in 2014 was relinquished in January. There were no reserves recorded on this undeveloped acreage. 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.

As of December 31, 2013, 23 percent of U.S. net undeveloped acreage and 54 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, 2013, based on average commodity prices in effect on the first day of each month in 2013, 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	458	184	2,006	977
Canada	81	26	1,294	323
Egypt[1]	119		622	223
Australia	23		627	127
North Sea	100	3	88	117
Argentina	14	4	289	66
Total Proved Developed	795	217	4,926	1,833
Proved Undeveloped:				
United States	196	64	667	371
Canada	56	10	439	139
Egypt[1]	16		190	48
Australia	37		975	199
North Sea	29		19	32
Argentina	2	1	122	24
Total Proved Undeveloped	336	75	2,412	813
TOTAL PROVED	1,131	292	7,338	2,646

(1) Includes total proved reserves of 90 MMboe attributable to a one-third noncontrolling interest in Egypt

As of December 31, 2013, Apache had total estimated proved reserves of 1,131 MMbbls of crude oil, 292 MMbbls of NGLs, and 7.3 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 2.65 billion barrels of oil or 15.9 Tcf of natural gas, of which oil represents 43 percent. As of December 31, 2013, the Company s proved developed reserves totaled 1,833 MMboe and estimated PUD reserves totaled 813 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, 2013, 2012, and 2011, 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 813 MMboe as of December 31, 2013, decreased by 57 MMboe from 870 MMboe of PUD reserves estimated at the end of 2012. During the year, Apache converted 154 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America, we converted 124 MMboe, with the remaining 30 MMboe in our international areas. We sold 109 MMboe and acquired 1 MMboe of PUD reserves during the year. We added 205 MMboe of new PUD reserves through extensions and discoveries.

During the year, a total of approximately $3.7 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2012. 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 $2.1 billion on PUD reserve development activity in North America and $1.6 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, 2013.

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 Chairman and 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 2013, 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 86 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 86 percent of total proved reserves, including 89 percent of proved developed reserves and 79 percent of PUD reserves.

During 2013, 2012, and 2011, Ryder Scott s review covered 92, 88, and 81 percent, respectively, of the Company s worldwide estimated proved reserves value and 86, 83, and 70 percent, respectively, of the Company s total proved reserves volume. 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. Ryder Scott s review of 2011 covered 68 percent of U.S., 69 percent of Canada, 58 percent of Argentina, 99 percent of Australia, 62 percent of Egypt, and 61 percent of the U.K. s total proved reserves. 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, 2013, we had 5,342 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 2013, we maintained regional exploration and/or production offices in Midland, Texas; Tulsa, Oklahoma; Houston, Texas; Calgary, Alberta; Cairo, Egypt; Perth, Western Australia; Aberdeen, Scotland; and Buenos Aires, Argentina. 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) 30 CFR 254.30. 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. In the event of a spill, CGA is the primary oil spill response association available to Apache and ADW. Apache and ADW have received approval for the Plans from BSEE. Apache and ADW personnel each review their respective Plan biennially and update where necessary.

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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 addition, CGA has contracted with Airborne Support Inc. to provide aircraft and dispersant capabilities for CGA member companies. In 2013, Apache incurred charges for CGA of approximately $700,000 based on a per-member fee and annual production.

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. OSRL has access to resources from the Global Response Network, a collaboration of seven major oil industry funded spill response organizations worldwide. If necessary, OSRL s resources may be, and have been, deployed to areas across the globe, including the Gulf of Mexico. In addition, in February 2012, ADW became 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. Furthermore, the spill response resources of other organizations are also available to both Apache and ADW as non-members, albeit at a higher cost. MSRC has an extensive inventory of oil spill response equipment, independent of and in addition to CGA s equipment. MSRC has contracts in place with over 100 environmental contractors around the country, in addition to hundreds of other companies that provide support services during spill response. In the event of a spill, MSRC will activate these contractors as necessary to provide additional resources or support services requested by its customers. NRC owns a variety of equipment, currently including shallow water portable barges, boom, high capacity skimming systems, inland workboats, vacuum transfer units, and mobile communication centers. NRC has access to hundreds of offshore vessels and supply boats worldwide. 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. In 2013, Apache s Gulf of Mexico Deepwater region incurred charges for NRC of $12,248 based on annual production and charges for MSRC of approximately $1.4 million based on annual production and total wells spud during the year.

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, 2013, Apache s investment in MWCC totals approximately $136 million.

Apache also participates in a number of industry-wide task forces that are studying ways to better access and control blowouts in subsea environments and increase containment and recovery methods. Two such task forces are the Subsea Well Control and Containment Task Force and the Offshore Operating Procedures Task Force.

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.

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However, we believe our diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across six countries, and 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 six 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.

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

The U.S. and other world economies continue to recover from the global financial crisis and recession that began in 2008. Growth has resumed but is modest and at an unsteady rate. The continuation of current global market conditions, uncertainty or further deterioration, including the economic instability in Europe and certain emerging markets, is likely to have significant long-term effects, including a future global economic growth rate that is slower than in the years leading up to the crisis, and more volatility may occur before any sustainable growth rate is achieved. 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.

Crude oil and natural gas prices are volatile, and a substantial reduction in these prices could adversely affect our 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 2013 ranged from a high of $110.53 per barrel to a low of $86.68 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2013 ranged from a high of $4.46 per MMBtu to a low of $3.11 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;
- electricity generation;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Significant declines in 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;
- a reduction in the carrying value of our crude oil and natural gas properties; or
- a reduction in 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.

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

Demand for oil and natural gas are, to a significant 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, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. 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 additional deepwater drilling laws and regulations, delays in the processing and approval of permits and other related developments in the Gulf of Mexico as well as our other locations resulting from 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 have imposed additional requirements with respect to development and production activities in the Gulf of Mexico and have delayed the approval of applications to drill in both deepwater and shallow-water areas.

Further, at this time, we cannot predict with any certainty what further impact, if any, the Deepwater Horizon incident may have on the regulation of offshore oil and gas exploration and development activity, or on the cost or availability of insurance coverage to cover the risks of such operations. 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;

- 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. 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 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 light of the extensive costs and liabilities related to the oil spill in the Gulf of Mexico in 2010, there has been public speculation as to whether one or more of the BP entities could 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). In the event that one or more of the BP entities were to become the subject of such a case or proceeding, 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. 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.

Several countries where we operate, including Australia, 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 2014, when released, is expected to include certain provisions that, if passed, will have an adverse effect on our financial position, results of operations, and cash flows.

To date, the Office of Management and Budget has not released a summary of the proposed U.S. federal budget for fiscal year 2014. It is anticipated that the proposed budget may recommend the repeal of many tax incentives and deductions that are currently used by U.S. oil and gas companies. These provisions could include the 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 been 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 restricting 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, including a requirement that certain transactions be cleared on exchanges and a requirement to post collateral (commonly referred to as margin) for such transactions. 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. In addition, it is possible that the CFTC, in conjunction with prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral.

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, our current derivative contracts do not require the posting of margin regardless of the size of our liability positions.

Depending on the rules and definitions adopted by the CFTC and prudential regulators, we could be required to post significant amounts of collateral with our dealer counterparties for derivative transactions. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and

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also cause us to incur additional debt and/or reduce capital investment. In addition, the final CFTC rules may also require the counterparties to our derivative instruments to move some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty.

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.

In February 2011, the former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power, announcing that it would remain in power until the presidential and parliamentary elections could be held. In June 2012, Mohamed Morsi of the Muslim Brotherhood s Freedom and Justice Party was elected as Egypt s new president. In July 2013, the Egyptian military removed President Morsi from power and installed Egypt s Chief Justice, Adly Mansour, as acting president of a temporary government, which is seeking to set a schedule for new parliamentary and presidential elections in 2014. In January 2014, Egyptians voted on and overwhelmingly approved a new constitution, and Mr. Mansour announced that the presidential election will be held prior to the parliamentary elections. While the date of the presidential election has not been announced, it is expected to be held by mid-April 2014. 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 could materially and adversely affect our business, financial condition, and results of operations. Our operations in Egypt contributed 19 percent of our 2013 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2013, 18 percent of our estimated discounted future net cash flows and 8 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, the United Kingdom, and Argentina. On a barrel equivalent basis, approximately 42 percent of our 2013 production was outside North America, and approximately 32 percent of our estimated proved oil and gas reserves on December 31, 2013 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;

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- 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;
- 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 or regional hostilities 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

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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, 2013, 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 2013, 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 2013 and 2012. 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.

	2013				2012			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 86.35	$ 72.20	$ 0.20	$ 0.17	$ 112.09	$ 91.48	$ 0.17	$ 0.15
Second Quarter	87.57	67.91	0.20	0.20	102.13	77.93	0.17	0.17
Third Quarter	89.17	75.07	0.20	0.20	94.87	81.55	0.17	0.17
Fourth Quarter	94.84	84.15	0.20	0.20	89.08	74.50	0.17	0.17

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2014 (last trading day of the month), was $80.26 per share. As of January 31, 2014, there were 394,724,983 shares of our common stock outstanding held by approximately 5,000 stockholders of record and 313,000 beneficial owners.

We have paid cash dividends on our common stock for 49 consecutive years through December 31, 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 will apply to the dividend on common shares payable on May 22, 2014, to stockholders of record on April 22, 2014, and subsequent dividends paid. 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.

On July 28, 2010, Apache issued 25.3 million depositary shares, each representing a 1/20th interest in a share of Apache s 6.00-percent Mandatory Convertible Preferred Stock, Series D (Preferred Share), or 1.265 million Preferred Shares. Upon conversion of the outstanding Preferred Shares on August 1, 2013, 14.4 million Apache common shares were issued.

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 will have the effect of terminating the Rights. The amendment will change the expiration date to March 7, 2014, and, thereby, accelerate the expiration of the Rights. The Company expects that the amendment will be fully executed on March 7, 2014.

For a description of the rights, please refer to Note 10 Capital Stock in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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 2014 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, 2008, through December 31, 2013. 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.

	2008	2009	2010	2011	2012	2013
Apache Corporation	$ 100.00	$ 139.51	$ 162.19	$ 123.87	$ 108.13	$ 119.51
S & P s Composite 500 Stock Index	100.00	126.46	145.51	148.59	172.37	228.19
DJ US Expl & Prod Index	100.00	140.56	164.09	157.22	166.37	219.35

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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, 2013, 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, 2013 numbers in the following table reflect a total of $1.2 billion ($613 million net of tax) in non-cash write-downs of the carrying value of the Company s U.S., North Sea, and Argentine 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. The 2009 numbers reflect a $2.82 billion ($1.98 billion net of tax) non-cash write-down of the carrying value of the Company s U.S. and Canadian proved oil and gas properties as of March 31, 2009.

	As of or for the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Income Statement Data					
Total revenues	$ 16,054	$ 17,078	$ 16,888	$ 12,092	$ 8,615
Net income (loss) attributable to common stock	2,188	1,925	4,508	3,000	(292)
Net income (loss) per common share:					
Basic	5.53	4.95	11.75	8.53	(0.87)
Diluted	5.50	4.92	11.47	8.46	(0.87)
Cash dividends declared per common share	0.80	0.68	0.60	0.60	0.60
Balance Sheet Data					
Total assets	$ 61,637	$ 60,737	$ 52,051	$ 43,425	$ 28,186
Long-term debt	9,672	11,355	6,785	8,095	4,950
Total equity	35,393	31,331	28,993	24,377	15,779
Common shares outstanding	396	392	384	382	336

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 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.

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, 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.

Although 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 assets for all other liquidity needs. In May 2013, the Company announced plans to divest approximately $4 billion of assets by year-end 2013 to enhance financial flexibility and rebalance our portfolio to an asset mix we believe will continue to generate strong returns, drive more predictable growth, and deliver value to our shareholders. By year-end, Apache completed more than $7 billion in asset sales, as discussed in Operational Developments below. The Company used the proceeds to pay down nearly $2.6 billion of debt and to repurchase $1 billion of Apache common shares under a 30-million share repurchase program authorized by the Company s Board of Directors, and we exited the year with nearly $2 billion in cash.

We remain steadfast to the business principles that have guided Apache s progress since our inception. Throughout the cycles of our industry, our strategic focus on growing a diverse portfolio has underpinned our ability to deliver production and reserve growth and competitive returns on invested capital for the benefit of our shareholders. Delivering successful results under this strategy is bolstered by Apache s unique culture. 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.

Financial and Operating Results

Continued volatility in the commodity price environment reinforces the importance of our asset portfolio. Our 2013 results reflected the benefit of our product balance, as combined crude oil and liquids represented 54 percent of our production but provided 83 percent of our $16.4 billion of oil and gas production revenues. In

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addition, approximately 65 percent of our 2013 crude oil production is priced relative to Dated Brent crudes and sweet crude from the Gulf Coast, which continue to be priced at a significant premium to WTI-based prices. After the sale of our Gulf of Mexico Shelf assets, less of our U.S. crude oil production is receiving these premium prices, which reduces our overall price realizations.

Results for the year ended December 31, 2013 include:

- Apache reported annual daily production of oil, natural gas, and natural gas liquids averaging 761 Mboe/d. Excluding the impact of the divested Gulf of Mexico Shelf and Canadian assets, production for the year would have increased 2 percent from 2012.

- Liquids production for the year averaged a record 411 Mboe/d, an increase of 4 percent from 396 Mboe/d in 2012. Crude oil accounted for 84 percent of liquids production. North American onshore liquids production increased 34 percent, averaging 179 Mboe/d in 2013 compared to 133 Mboe/d in 2012.

- Oil and gas production revenues totaled $16.4 billion, down $545 million from a record $16.9 billion in 2012, reflecting asset sales and lower realized prices compared to the prior year.

- Net cash provided by operating activities totaled $9.8 billion, an increase of 16 percent compared to 2012.

- Apache reported $2.2 billion in income attributable to common stock, or $5.50 per diluted common share, up from $1.9 billion, or $4.92 per share, in 2012. Earnings for 2013 and 2012 reflect the after-tax impact of oil and gas property write-downs totaling $659 million and $1.4 billion, respectively. For additional discussion regarding these write-downs, please refer to Note 1 Summary of Significant Accounting Policies Property and Equipment in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

- Apache s adjusted earnings, which exclude certain items impacting the comparability of results, were $3.2 billion, or $7.92 per diluted common share, down from $3.8 billion, or $9.48 per share, in 2012. Adjusted earnings is not a financial measure prepared in accordance with accounting principles generally accepted in the U.S. (GAAP). For a description of adjusted earnings and a reconciliation of adjusted earnings to income attributable to common stock, the most directly comparable GAAP financial measure, please see Non-GAAP Measures in this Item 7.

2014 Outlook

As we head into 2014, we remain committed to the Company s mission. At the end of 2012 and the beginning of 2013, Apache undertook a strategic review of our portfolio with the ultimate goal of focusing our company around the right mix of assets that can consistently generate strong returns, drive more predictable production growth, and create shareholder value. After completing more than $7 billion of divestitures in 2013 and announcing the agreed sale of our Argentine operations in 2014, our growth portfolio is centered on (i) increasing onshore North American liquids production that provides for predictable and attractive rates of return (ii) generating excess free cash flow from our international operations, and (iii) continuing longer-term growth initiatives which include our Wheatstone and Kitimat LNG projects.

We believe our core inventory of exploration and development projects offers numerous growth opportunities. Recent drilling successes and acquisitions of acreage positions across North America have built a robust drilling inventory for our Permian and Central regions that we intend to aggressively target because they are oil-prone and produce liquids-rich gas. Our plan for 2014 also includes further development of our major oil and gas discoveries and LNG projects in Australia and Canada, which, if completed, would enable us to monetize significant gas resources at prices more closely linked to crude oil.

Our initial 2014 capital budget is approximately $11.6 billion, or $11.1 billion excluding expenditures attributable to a one-third noncontrolling interest in Egypt. Approximately $7.1 billion is expected to be spent on projects in North America, with the remaining amount allocated across our international regions. While funds have been committed for certain 2014 exploration wells, long-lead development projects, and front-end engineering and design (FEED) studies, the majority of our drilling and development projects are discretionary and subject to acceleration, deferral, or cancellation as conditions warrant. Approximately $2.4 billion of our 2014 capital will be invested in our Kitimat and Wheatstone LNG projects, reflecting our current project interests. Apache is actively evaluating ways to right-size its level of participation in the Kitimat LNG project.

We closely monitor commodity prices, service cost levels, regulatory impacts, and numerous other industry factors, and we typically review and revise our exploration and development budgets quarterly based on changes to actual and predicted operating cash flows.

Apache s current capital budget is estimated to deliver an increase in 2014 production between 5 percent and 8 percent from full-year 2013 production levels when excluding the divested assets.

Operational Developments

Apache has a significant producing asset base as well as large undeveloped acreage positions that provide a platform for organic growth through sustainable lower-risk drilling opportunities, balanced by higher-risk, higher reward exploration. We are also continuing to advance several longer-term, individually significant development projects.

Exploration, Exploitation, and Development Activities

Our internally generated exploration and drilling opportunities and multi-year development projects provide the foundation for our growth. Highlights of our 2013 drilling successes, exploration discoveries, LNG project milestones, and other opportunities for continued growth include:

North American Activities

Record Drilling Activity in U.S. Onshore Regions During 2013 Apache increased production in the Permian Basin 17 percent relative to 2012 through an active drilling program utilizing an average of 42 rigs. Over half of the region s production is crude oil and 18 percent is natural gas liquids (NGL). Combined, this represents almost a quarter of Apache s total liquids production for 2013.

The Central region increased production almost 50 percent relative to 2012 as a result of our active oil and liquids-rich drilling program across our nearly two million gross acres in the Anadarko basin. During the year we operated an average of 27 drilling rigs, and we drilled or participated in drilling 322 gross wells with 98 percent success.

In 2013, U.S. production represented 44 percent of Apache s total worldwide production, an increase from 40 percent in 2012. Focused drilling programs in the Permian Basin and Anadarko basin continue to provide momentum for Apache s U.S. production growth.

International Activities

North Sea Development Apache s North Sea drilling success was highlighted with discoveries in the Tonto field. The Tonto-1 well, completed in April, had initial production of 10.3 Mb/d, and the Tonto-2 well, completed in September, had initial production of 8.3 Mb/d. Apache has a 100 percent working interest in the wells. The Tonto discovery follows Maule and Bacchus as the third new field brought online by Apache in the Forties area over the last three years. All three fields qualify for the U.K. s small field allowance, which provides economic incentives for operators to bring discoveries from small fields on production.

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Egypt Discoveries In August, Apache announced seven oil and gas discoveries in four different geologic basins in Egypt s Western Desert. In particular, the Riviera SW-1X discovery in the Abu Gharadig basin test-flowed 5,800 b/d and 2.8 Mcf/d from a Lower Bahariya sand with 24 feet of net pay. All seven discoveries have been tested and six are already producing.

Egypt Horizontal Drilling In 2013, the Company drilled its first well of a multi-well horizontal drilling program in the Abu Gharadig field. During December, this well produced an average of 1,681 b/d and 3 MMcf/d from a 1,970 foot lateral. The well was one of eight wells initiated during 2013 to test horizontal technology to increase recoveries in a variety of conventional and unconventional reservoirs. Additional horizontal drilling is planned in the Abu Gharadig and surrounding fields in 2014.

Australia Discoveries In July, Apache announced its Bianchi-1 natural gas discovery located 4 miles northeast of the 2011 Zola gas discovery offshore Western Australia in the Carnarvon Basin. The well logged 367 feet of net pay in eight reservoir zones between 15,577 and 17,530 feet subsea. Apache is in the early stages of evaluating the discovery and assessing potential commercial opportunities. Apache operates and owns a 30.25 percent working interest in the well.

Australia Macedon During the third quarter of 2013, Apache, along with operator and co-venturer BHP Billiton, officially commenced operations of the $1.5 billion Macedon natural gas facility, of which Apache owns a 28.57 percent interest. Macedon, Western Australia s fourth domestic gas hub, has a production capacity of approximately 200 MMcf of natural gas per day.

Australia Wheatstone LNG Project On October 1, 2013, Apache and its Australian partners finalized agreements to sell LNG to Tohoku Electric Power Company, Inc. from the Chevron-operated Wheatstone Project in Western Australia. The Wheatstone partners have agreed to supply 0.9 million metric tons per annum of LNG for up to 20 years, which brings the total LNG supplies contracted to approximately 85 percent. Apache owns a 13 percent share in the Wheatstone project.

Acquisition and Divestiture Activity

2014 Activity

Argentina Divestiture On February 12, 2014, Apache subsidiaries announced an agreement to sell all of its operations in Argentina to Sociedad Anónima (YPF) for cash consideration of $800 million plus the assumption of $52 million of bank debt as of June 30, 2013. The transaction is expected to close in the first quarter of 2014.

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. This noncontrolling interest is recorded separately in the Company s financial statements.

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. Total region production in 2013 was 71 Mboe/d, reflecting nine months of

Shelf production prior to the divestiture.

Canadian Divestitures In September, Apache completed the sale of primarily dry gas assets in Alberta 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. Combined, our 2013 divestitures totaled 13 percent of the region s production.

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. Chevron Canada will operate the LNG plant and pipeline while Apache Canada will continue to operate the upstream assets. Apache s net proceeds from the transaction were $396 million after post-closing adjustments.

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

2012 Activity

Cordillera Energy Partners III, LLC Acquisition On April 30, 2012, Apache completed the acquisition of Cordillera, a privately held exploration and production company, in a stock and cash transaction. Cordillera s properties include approximately 312,000 net acres in the Granite Wash, Tonkawa, Cleveland, and Marmaton plays in western Oklahoma and the Texas Panhandle. Apache issued 6,272,667 shares of common stock and paid approximately $2.7 billion of cash to the sellers as consideration for the transaction.

Yara Pilbara Holdings Pty Acquisition On January 31, 2012, a subsidiary of Apache Energy Limited completed the acquisition of a 49 percent interest in Yara Pilbara Holdings Pty Limited (YPHPL, formerly Burrup Holdings Limited) for $439 million, including working capital adjustments. Yara Australia Pty Ltd (Yara) owns the remaining 51 percent of YPHPL and operates the plant.

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Results of Operations

Oil and Gas Revenues

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

	For the Year Ended December 31,					
	2013		2012		2011	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
	($ in millions)					
Total Oil Revenues:						
United States	$ 5,262	41%	$ 4,662	35%	$ 4,163	33%
Canada	563	4%	492	4%	485	4%
North America	5,825	45%	5,154	39%	4,648	37%
Egypt(3)	3,528	27%	4,050	31%	4,169	33%
Australia	779	6%	1,218	9%	1,552	12%
North Sea	2,500	20%	2,517	19%	2,072	16%
Argentina	271	2%	271	2%	238	2%
International(3)	7,078	55%	8,056	61%	8,031	63%
Total(1)(3)	$ 12,903	100%	$ 13,210	100%	$ 12,679	100%
Total Gas Revenues:						
United States	$ 1,096	38%	$ 1,169	37%	$ 1,550	43%
Canada	587	21%	751	23%	1,033	29%
North America	1,683	59%	1,920	60%	2,583	72%
Egypt(3)	389	14%	504	16%	621	17%
Australia	361	13%	357	11%	182	5%
North Sea	194	7%	188	6%	19	0%
Argentina	202	7%	224	7%	204	6%
International(3)	1,146	41%	1,273	40%	1,026	28%
Total(2)(3)	$ 2,829	100%	$ 3,193	100%	$ 3,609	100%
NGL Revenues:						
United States	$ 544	81%	$ 395	73%	$ 391	75%
Canada	74	11%	79	14%	99	19%
North America	618	92%	474	87%	490	94%

Egypt[3]				0%	1	0%
North Sea	34	5%	46	8%		
Argentina	18	3%	24	5%	31	6%
International[3]	52	8%	70	13%	32	6%
Total[3]	$ 670	100%	$ 544	100%	$ 522	100%
Total Oil and Gas Revenues:						
United States	$ 6,902	42%	$ 6,226	37%	$ 6,104	36%
Canada	1,224	8%	1,322	8%	1,617	10%
North America	8,126	50%	7,548	45%	7,721	46%
Egypt[3]	3,917	24%	4,554	27%	4,791	29%
Australia	1,140	7%	1,575	9%	1,734	10%
North Sea	2,728	16%	2,751	16%	2,091	12%
Argentina	491	3%	519	3%	473	3%
International[3]	8,276	50%	9,399	55%	9,089	54%
Total[3]	$ 16,402	100%	$ 16,947	100%	$ 16,810	100%

(1) Financial derivative hedging activities decreased 2013, 2012, and 2011 oil revenues $47 million, $146 million, and $379 million, respectively.

(2) Financial derivative hedging activities increased 2013, 2012, and 2011 natural gas revenues $31 million, $414 million, and $272 million, respectively.

(3) 2013 includes revenues attributable to a noncontrolling interest in Egypt.

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Production

The following table presents production volumes by region:

	For the Year Ended December 31,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Oil Volume b/d:					
United States	146,907	10%	134,123	12%	119,415
Canada	17,724	12%	15,830	11%	14,252
North America	164,631	10%	149,953	12%	133,667
Egypt(1)(2)	89,561	(10%)	99,756	(4%)	103,912
Australia	19,329	(33%)	28,884	(24%)	38,228
North Sea	63,721	0%	63,692	17%	54,541
Argentina	9,375	(4%)	9,741	2%	9,597
International	181,986	(10%)	202,073	(2%)	206,278
Total	346,617	(2%)	352,026	4%	339,945
Natural Gas Volume Mcf/d:					
United States	781,335	(9%)	854,099	(1%)	864,742
Canada	497,515	(17%)	600,680	(5%)	632,550
North America	1,278,850	(12%)	1,454,779	(3%)	1,497,292
Egypt(1)(2)	356,454	1%	353,738	(3%)	365,418
Australia	223,433	4%	214,013	16%	185,079
North Sea	50,961	(11%)	57,457	NM	2,284
Argentina	187,390	(12%)	213,464	1%	212,311
International	818,238	(2%)	838,672	10%	765,092
Total	2,097,088	(9%)	2,293,451	1%	2,262,384
NGL Volume b/d:					
United States	54,580	63%	33,527	52%	22,111
Canada	6,689	7%	6,258	5%	5,958
North America	61,269	54%	39,785	42%	28,069
Egypt		0%		NM	49
North Sea	1,272	(21%)	1,618	NM	4
Argentina	2,102	(30%)	3,008	0%	3,018

International	3,374	(27%)	4,626	51%	3,071
Total	64,643	46%	44,411	43%	31,140
BOE per day[3]					
United States	331,709	7%	310,000	9%	285,650
Canada	107,332	(12%)	122,201	(3%)	125,636
North America	439,041	2%	432,201	5%	411,286
Egypt[2]	148,970	(6%)	158,713	(4%)	164,864
Australia	56,568	(12%)	64,552	(7%)	69,074
North Sea	73,487	(2%)	74,887	36%	54,925
Argentina	42,709	(12%)	48,326	1%	48,000
International	321,734	(7%)	346,478	3%	336,863
Total	760,775	(2%)	778,679	4%	748,149

(1) Gross oil production and gross natural gas production in Egypt for 2013, 2012, and 2011 was as follows:

	2013	2012	2011
Oil (b/d)	197,622	213,112	217,207
Gas (Mcf/d)	912,478	899,972	865,485

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

Oil (b/d)	3,912
Gas (Mcf/d)	16,494

(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,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Average Oil Price Per barrel					
United States	$ 98.14	3%	$ 94.98	(1%)	$ 95.51
Canada	87.00	2%	84.89	(9%)	93.19
North America	96.94	3%	93.91	(1%)	95.27
Egypt	107.94	(3%)	110.92	1%	109.92
Australia	110.42	(4%)	115.22	4%	111.22
North Sea	107.48	0%	107.97	4%	104.09
Argentina	79.05	4%	75.89	12%	68.02
International	106.55	(2%)	108.92	2%	106.67
Total[(1)]	101.99	(1%)	102.53	0%	102.19
Average Natural Gas Price Per Mcf:					
United States	$ 3.84	3%	$ 3.74	(24%)	$ 4.91
Canada	3.23	(6%)	3.42	(23%)	4.47
North America	3.61	0%	3.61	(24%)	4.72
Egypt	2.99	(23%)	3.90	(16%)	4.66
Australia	4.43	(3%)	4.55	69%	2.69
North Sea	10.43	17%	8.95	(60%)	22.25
Argentina	2.96	3%	2.87	9%	2.64
International	3.84	(7%)	4.15	13%	3.67
Total[(2)]	3.70	(3%)	3.80	(13%)	4.37
Average NGL Price Per barrel					
United States	$ 27.29	(15%)	$ 32.19	(34%)	$ 48.42
Canada	30.50	(12%)	34.63	(24%)	45.72
North America	27.64	(15%)	32.57	(32%)	47.85
Egypt				NM	66.36
North Sea	73.06	(5%)	77.11	18%	65.45
Argentina	23.64	10%	21.55	(23%)	27.90
International	42.27	3%	40.98	43%	28.56
Total	28.40	(15%)	33.45	(27%)	45.95

(1) Reflects a per-barrel decrease of $0.37, $1.13, and $3.05 in 2013, 2012, and 2011, respectively, from financial derivative hedging activities.

(2) Reflects a per-Mcf increase of $0.04, $0.49, and $0.33 in 2013, 2012, and 2011, respectively, from financial derivative hedging activities.

NM Not meaningful

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 2013 were essentially flat compared to 2012, although prices fluctuated throughout the year.

Continued volatility in the commodity price environment reinforces the importance of our diverse portfolio. While the market price received for natural gas varies among geographic areas, crude oil tends to trade within a tighter global range. With the exception of Argentina, price movements for all types and grades of crude oil

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generally move in the same direction. Crude oil prices realized in 2013 averaged $101.99 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 2013 we realized these premium prices on approximately 65 percent of our crude oil production. Our Egypt, Australia, and North Sea regions, which collectively comprised 50 percent of our 2013 worldwide oil production, received International Dated Brent pricing with 2013 oil realizations averaging $108.04 per barrel compared with 2012 oil realizations averaging $110.59 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. The majority of our gas sales contracts are indexed to prevailing local market prices, highlighting the importance of a geographically balanced portfolio. Our primary markets include North America, Egypt, Australia, the U.K., and Argentina. 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 $3.61 per Mcf in 2013, unchanged from 2012 levels.

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 $2.99 per Mcf in 2013, down 23 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 2013, the region averaged $4.43 per Mcf, a 3 percent decrease from 2012 levels.

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 $10.43 per Mcf in 2013, a 17 percent increase from an average of $8.95 per Mcf in 2012.

During 2013, we realized an average price of $2.96 per Mcf in Argentina, an increase of 3 percent over the 2012 average price of $2.87 per Mcf.

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

2013 vs. 2012 During 2013 crude oil revenues totaled $12.9 billion, $307 million lower than the 2012 total of $13.2 billion, driven by a 2 percent decrease in worldwide production. Average daily production in 2013 was 346.6 Mb/d, with prices averaging $101.99 per barrel. Crude oil represented 79 percent of our 2013 oil and gas production revenues and 46 percent of our equivalent production, compared to 78 and 45 percent, respectively, in the prior year. Lower production volumes reduced revenues $237 million, while slightly lower realized prices reduced revenues an additional $70 million.

Worldwide oil production decreased 5.4 Mb/d, however, when excluding the Gulf of Mexico Shelf and Canadian assets that we sold during the year, oil production increased 3.6 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 drilling and recompletion activity. Production from our remaining property base in Canada increased 1.9 Mb/d, or 12 percent, as a result of our continued focus on liquids-rich drilling targets. These increases were partially offset by a 20.1 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.

2012 vs. 2011 During 2012 crude oil revenues totaled $13.2 billion, $531 million higher than the 2011 total of $12.7 billion, driven by a 4 percent increase in worldwide production. Average daily production in 2012 was 352.0 Mb/d, with prices averaging $102.53 per barrel. Crude oil represented 78 percent of our 2012 oil and gas production revenues and 45 percent of our equivalent production, compared to 75 and 45 percent, respectively, in the prior year. Higher realized prices contributed $43 million to the increase in full-year revenues, while higher production volumes added another $488 million.

Worldwide oil production increased 12.1 Mb/d, driven by a 14.7 Mb/d increase in the U.S. The Permian region increased 9.2 Mb/d on increased drilling and recompletion activity. The Central region increased 7.4 Mb/d on properties added from the Cordillera acquisition and drilling and recompletion activity. North Sea production increased 9.2 Mb/d primarily on volumes from the 2011 Mobil North Sea acquisition. Australia production decreased 9.3 Mb/d as a result of natural decline from our Pyrenees and Van Gogh fields.

Natural Gas Revenues

2013 vs. 2012 Natural gas revenues of $2.8 billion for 2013 were $364 million lower than 2012, the result of a 9 percent decrease in production volumes and a 3 percent decrease in realized prices. Worldwide production decreased 196.4 MMcf/d, lowering revenues by $273 million. Realized prices in 2013 averaged $3.70 per Mcf, a decrease of $0.10 per Mcf, which reduced revenues by an additional $91 million.

Worldwide gas production decreased 9 percent; however, excluding production from the Gulf of Mexico Shelf and Canadian assets sold during the year, gas production declined only 3 percent, or 60 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. Argentina production decreased 26 MMcf/d on lower capital investments pending negotiations of extensions of several of our concessions, and 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.

2012 vs. 2011 Natural gas revenues for 2012 of $3.2 billion were $416 million lower than 2011, the result of a 13 percent decrease in realized prices partially offset by a 1 percent increase in production volumes. Realized prices in 2012 averaged $3.80 per Mcf, a decrease of $0.57 per Mcf, which reduced revenues by $467 million. Worldwide production rose 31.1 MMcf/d, adding $51 million to revenues.

Worldwide gas production rose 1 percent on increases in the North Sea and Australia, partially offset by decreases in North America. North Sea daily production increased 55.2 MMcf/d, primarily as a result of the 2011 Mobil North Sea acquisition. Daily gas production in Australia increased 28.9 MMcf/d on new contracts associated with the recently completed gas processing facilities at Devil Creek. Central region rose 29.6 MMcf/d on production from the Cordillera acquisition. Daily production in Canada and the Gulf of Mexico onshore and offshore regions decreased 31.9 MMcf/d and 47.9 MMcf/d, respectively, as drilling and recompletion activity shifted from dry gas to liquids-rich gas properties.

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NGL Revenues

2013 vs. 2012 NGL revenues totaled $670 million in 2013, an increase of $126 million from 2012, the result of a 46 percent increase in production volumes partially offset by a 15 percent decrease in realized prices. Worldwide production rose 20.2 Mb/d, adding $208 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 $28.40 per Mcf barrel, a decrease of $5.05 per barrel, which reduced revenues by $82 million.

2012 vs. 2011 NGL revenues totaled $544 million in 2012, an increase of $22 million from 2011, the result of a 43 percent increase in production volumes partially offset by a 27 percent decrease in realized prices. Worldwide production rose 13.3 Mb/d, adding $164 million to revenues. This increase was driven by drilling and recompletion activity in the U.S. Central and Permian regions and production from the Cordillera acquisition in the Central region. Realized prices in 2012 averaged $33.45 per Mcf barrel, a decrease of $12.50 per barrel, which reduced revenues by $142 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 2013 operating expenses include costs attributable to a noncontrolling interest in Egypt.

	For the Year Ended December 31,					
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
		(In millions)			**(Per boe)**	
Depreciation, depletion and amortization:						
Oil and gas property and equipment						
Recurring	$ 5,114	$ 4,812	$ 3,814	$ 18.42	$ 16.88	$ 13.97
Additional	1,176	1,926	109	4.24	6.76	0.40
Other assets	410	371	281	1.47	1.30	1.03
Asset retirement obligation accretion	243	232	154	0.88	0.81	0.56
Lease operating costs	3,056	2,968	2,605	11.00	10.41	9.54
Gathering and transportation costs	297	303	296	1.06	1.08	1.08
Taxes other than income	832	862	899	3.00	3.02	3.29
General and administrative expense	503	531	459	1.81	1.86	1.68
Acquisitions, divestitures & transition	33	31	20	0.12	0.11	0.07
Financing costs, net	174	165	158	0.63	0.58	0.58
Total	$ 11,838	$ 12,201	$ 8,795	$ 42.63	$ 42.81	$ 32.20

Recurring Depreciation, Depletion and Amortization (DD&A)

The following table details the changes in recurring DD&A of oil and gas properties between December 31, 2011, and December 31, 2013:

		Recurring DD&A (In millions)
2011 DD&A	$	3,814
Volume change		231
DD&A Rate change		767
2012 DD&A	$	4,812
Volume change		(83)
DD&A Rate change		385
2013 DD&A	$	5,114

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2013 vs. 2012 Recurring full-cost depletion expense increased $302 million on an absolute dollar basis: $385 million on rate partially offset by a decrease of $83 million from lower volumes. Our full-cost depletion rate increased $1.54 to $18.42 per boe reflecting acquisition and drilling costs that exceed our historical levels.

2012 vs. 2011 Recurring full-cost depletion expense increased $998 million on an absolute dollar basis: $767 million on higher costs and $231 million from additional production. Our full-cost depletion rate increased $2.91 to $16.88 per boe as costs to acquire, find, and develop reserves, which were significantly impacted by higher oil prices, exceeded our historical cost basis. Price related reserve revisions in North America also had a negative impact on the rate.

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.

In 2013 we recorded non-cash write-downs of the carrying value of the Company s proved oil and gas properties totaling $1.1 billion. The after-tax impact of these write-downs was $356 million in the U.S., $139 million in the North Sea, and $118 million in Argentina. 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 2013 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties in Australia, the North Sea and the U.S. Gulf of Mexico regions.

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The following table identifies changes in Apache s LOE rate from 2011 to 2013:

For the Year Ended December 31, 2013		For the Year Ended December 31, 2012	
	Per boe		Per boe
2012 LOE	$ 10.41	2011 LOE	$ 9.54
Divestitures[1]	(0.12)	Repairs and maintenance	0.39
Power and fuel costs	0.19	Labor and pumper costs	0.31
Labor and overhead costs	0.17	Non-operated property costs	0.12
Non-operated property costs	0.13	Workover costs	0.06
Transportation	0.12	Other	0.10
Workover costs	0.07	Other decreased production	0.01
Repairs and maintenance	0.07	Acquisitions[1]	(0.12)
Other	0.11		
Other increased production	(0.15)		
2013 LOE	$ 11.00	2012 LOE	$ 10.41

(1) Per-unit impact of acquisitions and 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., Canada, and Argentina, 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,		
	2013	2012	2011
		(In millions)	
Canada	$ 155	$ 163	$ 166
U.S.	84	69	64
Egypt	42	39	34

North Sea	7	24	25
Argentina	9	8	7
Total Gathering and transportation	$ 297	$ 303	$ 296

2013 vs. 2012 Gathering and transportation costs decreased $6 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.

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2012 vs. 2011 Gathering and transportation costs increased $7 million from 2011. The U.S. costs for 2012 increased $5 million as compared to 2011 on increased production in the Central region, primarily resulting from our acquisition of Cordillera. Egypt s costs were up $5 million on a higher number of sales cargoes, increased terminal fees, and higher vessel freight costs. Canada s costs decreased $3 million from a decline in activity in the region.

Taxes Other Than Income

Taxes other than income primarily consist of U.K. Petroleum Revenue Tax (PRT), severance taxes on properties onshore and in state or provincial waters off the coast of the U.S., Australia, and Argentina, 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. We are subject to a variety of other taxes including U.S. franchise taxes, Australian Petroleum Resources Rent Tax, 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,		
	2013	2012	2011
		(In millions)	
U.K. PRT	$ 382	$ 451	$ 538
Severance taxes	254	220	212
Ad valorem taxes	113	104	94
Other	83	87	55
Total Taxes other than income	$ 832	$ 862	$ 899

2013 vs. 2012 Taxes other than income were $30 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 $9 million to severance and ad valorem tax expense, respectively.

2012 vs. 2011 Taxes other than income were $37 million lower than 2011. U.K. PRT decreased $87 million over the comparable 2011 period as a result of a decrease in net receipts, primarily driven by lower revenues on qualifying fields during the year. Property acquisitions in 2011 and 2012 resulted in increases of $8 million and $10 million to severance and ad valorem tax expense, respectively.

General and Administrative Expenses

2013 vs. 2012 General and administrative (G&A) expenses decreased $28 million, or 5 percent, from 2012. On a per-unit basis, G&A expenses were down $0.05 to $1.86 per boe, with the benefit of lower costs partially offset by the impact of lower production.

2012 vs. 2011 G&A expenses increased $72 million, or 16 percent, from 2011. On a per-unit basis, G&A expenses increased 11 percent, or $0.18 per boe: $0.12 per boe primarily relates to stock-based performance plan charges and $0.14 per boe relates to growth-related increases, less $0.08 on increased production.

Acquisitions, Divestitures, and Transition Costs

In 2013, the Company recognized $33 million in acquisitions, divestitures, and transition costs related to the sale of our Gulf of Mexico Shelf assets to Fieldwood and our partnership with Sinopec in Egypt.

In 2012, the Company recognized $31 million in acquisitions, divestitures, and transition costs, reflecting expenses related to our 2011 acquisition of Mobil North Sea Limited and our 2012 acquisition of Cordillera.

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In 2011, the Company recognized $20 million in acquisitions, divestitures, and transition costs, reflecting additional expenses related to our 2010 BP asset acquisitions and the Mariner merger as well as costs arising from our 2011 acquisition of Mobil North Sea Limited.

Financing Costs, Net

Financing costs incurred during the period comprised the following:

	For the Year Ended December 31, 2013	2012	2011
		(In millions)	
Interest expense	$ 571	$ 509	$ 433
Amortization of deferred loan costs	8	7	5
Capitalized interest	(374)	(334)	(263)
Gain on extinguishment of debt	(16)		
Interest income	(15)	(17)	(17)
Total Financing costs, net	$ 174	$ 165	$ 158

2013 vs. 2012 Net financing costs increased $9 million from 2012. The increase is primarily related to a $62 million increase in interest expense from debt issuances during 2012, partially offset by a $40 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.

2012 vs. 2011 Net financing costs increased $7 million from 2011. The increase is primarily related to a $76 million increase in interest expense from debt issuances during 2012, partially offset by a $71 million increase in capitalized interest resulting from additional unproved property balances associated with the significant undeveloped acreage from the Cordillera acquisition and the U.S. New Ventures program.

Provision for Income Taxes

The 2013 provision for income taxes totaled $1.9 billion, representing an effective tax rate of 45.7 percent. The 2013 effective rate reflects the tax benefit from the $1.2 billion non-cash write-downs in the U.S., North Sea, Argentina, 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.

The 2012 provision for income taxes totaled $2.9 billion, representing an effective tax rate of 59.0 percent. The 2012 effective rate reflects the tax impact from the $1.9 billion Canadian non-cash write-down, a $118 million charge for a North Sea decommissioning tax rate change and other tax adjustments primarily associated with valuation allowances in Canada and Argentina. Excluding these items, the 2012 effective tax rate would have been 44 percent, approximately comparable with the current year rate and the 2011 effective rate of 43 percent.

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 occasional 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 exploration and development activities and our ability to acquire additional reserves at reasonable costs.

We believe the liquidity and capital resource alternatives available to Apache, combined with internally generated 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 contingencies.

In May 2013, Apache announced that it would divest approximately $4 billion in assets to enhance financial flexibility and rebalance our portfolio to an asset mix we believe will continue to generate strong returns, drive predictable growth, and deliver value to our shareholders. As of year-end 2013, Apache completed more than $7 billion in asset sales and used the proceeds to pay down nearly $2.6 billion in debt and to repurchase $1 billion in Apache common shares under a 30-million share repurchase program authorized by the Company s Board of Directors. The Company ended the year with nearly $2 billion of cash on hand.

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, 2013	2012	2011
		(In millions)	
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 9,835	$ 8,504	$ 9,953
Commercial paper and bank loan borrowings, net		549	
Sale of Gulf of Mexico Shelf properties	3,702		
Proceeds from sale of Egypt noncontrolling interest	2,948		
Proceeds from Kitimat LNG transaction, net	396		
Proceeds from sale of oil and gas properties, other	307	27	422
Fixed-rate debt borrowings		4,978	
Other	21		84
	17,209	14,058	10,459
Uses of Cash and Cash Equivalents:			
Capital expenditures[(1)]	$ 11,220	$ 9,531	$ 7,078
Acquisitions	215	2,918	1,813
Equity investment in Yara Pilbara Holdings Pty Limited (YPHPL)		439	
Commercial paper, credit facility and bank loan repayments, net	513		925
Dividends paid	360	332	306
Shares repurchased	997		
Payments on fixed-rate debt	2,072	400	
Other	86	573	176
	15,463	14,193	10,298
Increase (decrease) in cash and cash equivalents	$ 1,746	$ (135)	$ 161

(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 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 operating activities for 2013 totaled $9.8 billion, up $1.3 billion from 2012. The increase 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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Proceeds from Sale of Oil and Gas Properties and Noncontrolling Interest in Egypt

During 2013 Apache completed the sale of certain properties in Canada and the U.S. for $4.4 billion. Apache also completed the sale of a one-third minority participation in its Egypt oil and gas business to Sinopec for $2.95 billion. 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.

Capital Investments

We fund exploration and development (E&D) activities primarily through operating cash flows and budget capital expenditures based on projected operating cash flows. Our operating cash flows, both in the short and long term are impacted by highly volatile oil and natural gas prices, production levels, industry trends impacting operating expenses and our ability to continue to acquire and find high-margin reserves at competitive prices. As a majority of our exploration and development activity is discretionary, we routinely adjust our capital budget on a quarterly basis in response to changing market conditions and operating cash flow forecasts.

We have used a combination of operating cash flows, borrowings under lines of credit and our commercial paper program, and occasionally, issues of public debt or common stock to fund other significant capital investments.

The following table details capital investments for each country in which we do business.

	For the Year Ended December 31,		
	2013	2012	2011
		(In millions)	
Exploration and Development:			
United States	$ 5,473	$ 5,151	$ 2,768
Canada	720	590	817
North America	6,193	5,741	3,585
Egypt[1]	1,166	1,074	896
Australia	1,179	873	576
North Sea	874	886	823
Argentina	182	289	346
Other International	22	98	61
International[1]	3,423	3,220	2,702
Worldwide E&D Costs[1]	9,616	8,961	6,287
Gathering, Transmission, and Processing Facilities (GTP):			
United States	169	75	27
Canada	135	172	148
Egypt[1]	82	33	111
Australia	745	441	345
Argentina	11	16	12

North Sea	1	1	
Total GTP Costs[1]	1,143	738	643
Asset Retirement Costs	484	948	819
Capitalized Interest	374	334	263
Capital Expenditures	$ 11,617	$ 10,981	$ 8,012
Acquisitions, including GTP	$ 377	$ 3,543	$ 3,189
Asset Retirement Costs Acquired	53	84	592
Total Acquisitions	$ 430	$ 3,627	$ 3,781

(1) Includes 2013 capital costs attributable to a noncontrolling interest in Egypt.

Exploration and Development Worldwide E&D expenditures for 2013 totaled $9.6 billion, or 7 percent above 2012. E&D spending in North America was up 8 percent from the prior year and totaled 64 percent of worldwide E&D spending. Expenditures in the U.S. reflect increased drilling activity in the Anadarko basin and Permian Basin, where we continue to shift to more horizontal drilling. In the Permian Basin, we averaged operating 42 rigs during the year. Our recent drilling successes in the Permian has led the region to increase the number of horizontal drilling rigs being utilized throughout 2013, and now approximately half of our rigs are drilling horizontal wells that, given their nature, are more costly than vertical wells. In our Central region we have increased our activity in the Whittenburg and Anadarko basins where our active drilling programs continued to expand. E&D spending in Canada increased 22 percent from the prior-year period as the region has continued to target oil and liquids-rich gas plays across its acreage and drilling more horizontal wells.

E&D expenditures outside of North America increased 6 percent over 2012. Australian expenditures were up $306 million as both exploration and development drilling continued with high activity levels. Egypt was $92 million higher than the prior year on continued drilling activity across all major basins. E&D spending in the North Sea was up $12 million on Beryl field development activity, following the field s acquisition at the end of 2011. Argentina expenditures were down $107 million on decreased drilling activity.

Gathering, Transmission and Processing Facilities We invested $1.1 billion in GTP in 2013 compared to $738 million in 2012, primarily related to activities associated with the Wheatstone LNG project in Australia.

Acquisitions We acquired $377 million of oil and gas properties and GTP in 2013 compared to $3.5 billion in 2012. Acquisition capital expenditures occur as attractive opportunities arise and, therefore, vary from year to 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.

Payments on Fixed-Rate Debt

During 2013, Apache repaid the $500 million aggregate principal amount of its 5.25 percent notes that matured on April 15, 2013 and the $400 million aggregate principal amount of its 6.00 percent notes that matured on September 15, 2013 by borrowing under our commercial paper program.

In November 2013 the Company announced a cash tender offer to purchase up to $850 million aggregate principal amount of five series of its outstanding notes. On December 20, 2013, the Company accepted for purchase $669 million principal amount of its 2.625 percent notes due 2023 and $181 million principal amount of its 3.25 percent notes due 2022. Apache paid the holders an aggregate of approximately $811 million in cash reflecting principal, the discount to par, and accrued and unpaid interest.

In December 2013, Apache Finance Canada Corporation (Apache Finance Canada) fully redeemed $350 million principal amount of its 4.375 percent notes due in 2015. The notes were redeemed pursuant to the provisions of the notes indenture. Apache paid the holders an aggregate of approximately $371 million in cash reflecting principal, the premium to par, and accrued and unpaid interest.

Dividends

The Company has paid cash dividends on its common stock for 49 consecutive years through 2013. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other relevant factors. Common stock dividends paid during 2013 totaled $303 million, compared with $256 million in 2012 and $230 million in 2011. The Company paid dividends on its Series D Preferred Stock totaling $57 million in 2013, compared with $76 million in each 2012 and 2011. The preferred stock was converted to common stock in August 2013.

In the first quarter of 2013 the Board of Directors approved an 18 percent increase to $0.20 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, 2013, to stockholders of record on April 22, 2013, and subsequent dividends paid.

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 will apply to the dividend on common shares payable on May 22, 2014, to stockholders of record on April 22, 2014, and subsequent dividends paid.

Shares Repurchased

In May 2013, Apache s Board of Directors authorized the purchase of up to 30 million shares of the Company s common stock, valued at approximately $2 billion when first announced. 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, with the repurchase of 2,924,271 shares at an average price of $85.47 during the month of June. During the fourth quarter of 2013, 8,297,648 shares were repurchased at an average price of $90.08. An additional 2,393,917 shares were purchased subsequent to December 31, 2013 at an average cost of $84.67. The Company anticipates that further purchases will primarily be made with proceeds from asset dispositions, but the Company is not obligated to acquire any specific number of shares.

Liquidity

	At December 31, 2013	At December 31, 2012
	(In millions, except percentages)	
Cash and cash equivalents	$ 1,906	$ 160
Total debt	9,725	12,345
Equity	35,393	31,331
Available committed borrowing capacity	3,300	2,811
Floating-rate debt/total debt	1%	5%
Percent of total debt-to-capitalization	22%	28%

Cash and Cash Equivalents

At December 31, 2013, we had $1.9 billion in cash and cash equivalents, of which $1.7 billion of cash was held by foreign subsidiaries, and approximately $158 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. Almost all of the cash is denominated in U.S. dollars and, at times, is invested in highly liquid, investment-grade securities with maturities of three months or less at the time of purchase. We intend to use cash from our international subsidiaries to fund international projects.

Debt

At December 31, 2013, outstanding debt, which consisted of notes, debentures, and uncommitted bank lines, totaled $9.7 billion. Current debt consists of $53 million borrowed under uncommitted money market and overdraft lines of credit in Argentina and Canada. We have $900 million of debt maturing in 2017, $550 million maturing in 2018 and the remaining $8.3 billion maturing intermittently in years 2019 through 2096.

Available Credit Facilities

As of December 31, 2013, the Company had unsecured committed revolving syndicated bank credit facilities totaling $3.3 billion, of which $1.0 billion matures in August 2016 and $2.3 billion matures in June 2017. The facilities consist of 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. In July 2013, we amended our $1.0 billion U.S. credit facility to conform certain representations, covenants, and events of default to those in our $1.7 billion U.S. credit facility. The amendments did not affect the amount or repayment terms of the $1.0 billion U.S. facility. As of December 31, 2013, aggregate available borrowing capacity under the Company s credit facilities was $3.3 billion. The Company s committed credit facilities are used to support Apache s commercial paper program.

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, 2013, the margin over LIBOR for committed loans was 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 0.125 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 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, 2013, the Company s debt-to-capitalization ratio was 22 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 $3.1 billion as of December 31, 2013. 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, 2013.

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

The Company has available a $3.0 billion commercial paper program, which 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 2013 weighted-average interest rate for commercial paper was 0.38 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 2016 and 2017, are available as a 100 percent backstop. As of December 31, 2013, the Company had no outstanding commercial paper. At December 31, 2012, the Company had $489 million in commercial paper outstanding.

Letter of Credit Collateral

In the event Apache s credit rating is downgraded by Moody s and S&P, Apache will need to provide a letter of credit as collateral to secure certain abandonment obligations. In conjunction with the Forties field and Mobil North Sea Limited acquisitions in 2003 and 2012, respectively, Apache assumed the abandonment obligation of each seller for those properties. 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.

Total Debt-to-Capitalization

The Company s debt-to-capitalization ratio as of December 31, 2013, was 22 percent as compared to 28 percent at December 31, 2012. The decrease in our debt-to-capitalization ratio is directly related to the 2013 payment of fixed and floating debt and repurchase of shares. Apache has historically utilized available committed borrowing capacity, access to both debt and equity capital markets, and proceeds from the occasional sale of nonstrategic assets for liquidity and capital resources needs.

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.

We believe the liquidity and capital resource alternatives available to Apache, combined with internally-generated 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 or contingencies.

Contractual Obligations

The following table summarizes the Company s contractual obligations as of December 31, 2013. 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**	**2014**	**2015-2016**	**2017-2018**	**2019 & Beyond**
			(In millions)			
Debt, at face value	Note 6	$ 9,784	$ 53	$ 1	$ 1,450	$ 8,280
Interest payments	Note 6	10,234	482	965	907	7,880
Drilling rig commitments[2]	Note 8	974	376	429	157	12
Purchase obligations[3]	Note 8	1,759	1,002	533	204	20
Firm transportation agreements	Note 8	683	158	223	129	173
Office and related equipment	Note 8	391	46	101	95	149
Other operating lease obligations[4]	Note 8	686	190	295	193	8
Total Contractual Obligations		$ 24,511	$ 2,307	$ 2,547	$ 3,135	$ 16,522

(1)

This table does not include the Company s liability for dismantlement, abandonment, and restoration costs of oil and gas properties, derivative liabilities, pension or postretirement benefit obligations, or tax reserves. For additional information regarding these liabilities, please see Notes 5, 3, 9, and 7, 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.

(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,

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minimum or variable price provisions; and the appropriate timing of the transaction. These include minimum commitments associated with take-or-pay contracts, hydraulic fracturing service agreements, obtaining and processing seismic data, and contractual obligations to buy or build oil and gas plants and facilities, including LNG facilities.

(4) 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, FPSOs, and aircraft, among other things.

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 $93 million for environmental remediation and approximately $10 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 $79 million accrued as of December 31, 2013, 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 pollution, and other risks. Our insurance coverage includes deductibles 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 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.

Our insurance policies generally renew in January and June of each year. 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 $856 million of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $149 million sub-limit for currency inconvertibility.

In addition, the Company has a separate policy with OPIC, which 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.

Non-GAAP Measures

The Company makes reference to some measures in discussion of its financial and operating highlights that are not required by or presented in accordance with GAAP. Management uses these measures in assessing operating results and believes the presentation of these measures provides information useful in assessing the Company s financial condition and results of operations. These non-GAAP measures should not be considered as alternatives to GAAP measures and may be calculated differently from, and therefore may not be comparable to, similarly titled measures used at other companies.

Adjusted Earnings

To assess the Company s operating trends and performance, management uses Adjusted Earnings, which is net income excluding certain items that management believes affect the comparability of operating results. Management believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported company earnings for items that may obscure underlying fundamentals and trends. The reconciling items below are the types of items management excludes and believes are frequently excluded by analysts when evaluating the operating trends and comparability of the Company s results.

	For the Year Ended December 31,		
	2013	**2012**	**2011**
	(In millions, except per share data)		
Income (Loss) Attributable to Common Stock (GAAP)	$ 2,188	$ 1,925	$ 4,508
Adjustments:			
Oil & gas property write-downs, net of tax(1)	659	1,427	60
Deferred tax on distributed foreign earnings	225		
Deferred tax adjustments	58	226	(75)
U.K. income tax adjustments		118	218
Commodity derivative mark-to-market, net of tax(2)	142	51	
Acquisitions, divestitures, and transition, net of tax(3)	21	19	13
Unrealized foreign currency fluctuation impact on deferred tax expense	(123)	1	(73)
Adjusted Earnings (Non-GAAP)	$ 3,170	$ 3,767	$ 4,651
Net Income per Common Share Diluted (GAAP)	$ 5.50	$ 4.92	$ 11.47
Adjustments:			
Oil & gas property write-downs, net of tax(1)	1.63	3.53	0.15
Deferred tax on distributed foreign earnings	0.55		

Deferred tax adjustments	0.14	0.56	(0.19)
U.K. income tax adjustments		0.30	0.55
Commodity derivative mark-to-market, net of tax(2)	0.35	0.13	
Acquisitions, divestitures, and transition, net of tax(3)	0.05	0.04	0.03
Unrealized foreign currency fluctuation impact on deferred tax expense	(0.30)		(0.18)
Adjusted Earnings Per Share Diluted (Non-GAAP)	$ 7.92	$ 9.48	$ 11.83

(1) Write-downs of our U.S., North Sea, and Argentina proved oil and gas property balances of $552 million, $368 million, and $181 million, respectively, were recorded in 2013, for which tax benefits of $196 million, $229 million, and $63 million, respectively, were recognized. Separately, a $75 million non-cash write-down was recorded related to the Company s exit of operations in Kenya, for which a tax benefit of $29 million was recognized. A non-cash write-down on the carrying value of our proved oil and gas property balances in Canada of $1.9 billion was recorded during 2012, for which a tax benefit of $474 million was recognized. The tax effect was calculated utilizing the Canadian statutory rate currently in effect.

(2) Commodity derivative mark-to-market losses recorded in 2013 totaled $221 million, for which a tax benefit of $79 million was recognized.

(3) Acquisitions, divestitures, and transition costs recorded in 2013, 2012, and 2011, totaled $33 million, $31 million, and $20 million, respectively, for which tax benefits of $12 million, $12 million, and $7 million, respectively, were recognized. The tax effect was calculated utilizing the statutory rates in effect in each country where costs were incurred.

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. 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.

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 2013, our average crude oil realizations have remained flat at $101.99 per barrel compared to $102.53 per barrel in 2012. Our average natural gas price realizations decreased 3 percent in 2013 to $3.70 per Mcf from $3.80 per Mcf in 2012.

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 2013 approximately 8 percent of our natural gas production and approximately 42 percent of our crude oil production was subject to financial derivative hedges, compared with 13 percent and 13 percent, respectively, in 2012.

On December 31, 2013, the Company had open natural gas derivatives in an asset position with a fair value of $3 million. A 10 percent movement in natural gas prices would move the fair value by approximately $463,000. The Company also had open oil derivatives in a liability position with a fair value of $301 million. A 10 percent increase in oil prices would increase the liability by approximately $476 million, while a 10 percent decrease in prices would move the derivatives to an asset position of $175 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2013. 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 99.5 percent of the Company s debt. At December 31, 2013, total debt included $53 million of floating-rate debt. As a result, Apache s annual interest costs in 2013 will fluctuate based on short-term interest rates on approximately 0.5 percent of our total debt outstanding at December 31, 2013. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $1.6 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. Argentine revenues and expenditures are largely denominated in U.S. dollars, but are converted into Argentine pesos at the time of payment. Revenue and disbursement transactions denominated in Australian dollars, Canadian dollars, British pounds, and Argentine pesos 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, British pound, and Argentine peso against the U.S. dollar as of December 31, 2013, would result in a foreign currency net loss or gain, respectively, of approximately $186 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 in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2013, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, plan, believe, or continue or similar terminology. believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- the market prices of oil, natural gas, NGLs and other products or services;
- our commodity derivative and hedging arrangements;
- the supply and demand for oil, natural gas, NGLs and other products or services;
- production and reserve levels;
- drilling risks;

economic and competitive conditions;

the availability of capital resources;

capital expenditure and other contractual obligations;

currency exchange rates;

weather conditions;

inflation rates;

the availability of goods and services;

legislative or regulatory changes;

the impact on our operations due to changes in the Egyptian government;

- the integration of acquisitions;
- terrorism or cyber attacks;
- occurrence of property acquisitions or divestitures;
- the securities or capital markets and related risks such as general credit, liquidity, market, and interest-rate risks; and
- other factors disclosed under Items 1 and 2 Business and Properties Estimated Proved Reserves and Future Net Cash Flows, Item 1A Risk Factors, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this Form 10-K.

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

The financial statements and supplementary financial information required to be filed under this Item 8 are presented on pages F-1 through F-73 in Part IV, Item 15 of this Form 10-K and are incorporated herein by reference.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

The financial statements for the fiscal years ended December 31, 2013, 2012, and 2011, included in this report, have been audited by Ernst & Young LLP, registered public accounting firm, as stated in their audit report appearing herein. There have been no changes in or disagreements with the accountants during the periods presented.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

G. Steven Farris, the Company s Chairman and Chief Executive Officer, in his capacity as principal executive officer, and Thomas P. Chambers, the Company s Senior Vice President, Finance, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2013, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company s disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the Commission s rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure. We also made no changes in internal controls over financial reporting during the quarter ending December 31, 2013, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

We periodically review the design and effectiveness of our disclosure controls, including compliance with various laws and regulations that apply to our operations both inside and outside the United States. We make modifications to improve the design and effectiveness of our disclosure controls and may take other corrective action, if our reviews identify deficiencies or weaknesses in our controls.

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Management s Annual Report on Internal Control over Financial Reporting; Attestation Report of the Registered Public Accounting Firm

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to the Report of Management on Internal Control Over Financial Reporting, included on Page F-1 in Part IV, Item 15 of this Form 10-K.

The independent auditors attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to the Report of Independent Registered Public Accounting Firm, included on Page F-3 in Part IV, Item 15 of this Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2013, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

On February 11, 2014, the Company appointed Alfonso Leon as executive vice president and chief financial officer effective as of February 13, 2014, and Thomas P. Chambers ceased service as the chief financial officer as of the close of business on that date, assuming the new position of the Company s senior vice president, Finance. Continuing through March 1, 2014, Mr. Chambers will continue to perform the functions of Company s principal financial officer; Mr. Leon will assume the role of principal financial officer effective as of that date.

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PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information set forth under the captions Nominees for Election as Directors, Continuing Directors, Executive Officers of the Company, and Securities Ownership and Principal Holders in the proxy statement relating to the Company s 2014 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, we are required to adopt a code of business conduct and ethics for our directors, officers, and employees. In February 2004, the Board of Directors adopted the Code of Business Conduct (Code of Conduct), and revised it in November 2013. The revised Code of Conduct also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access the Company s Code of Conduct on the Governance page of the Company s website at www.apachecorp.com. Any shareholder who so requests may obtain a printed copy of the Code of Conduct by submitting a request to the Company s corporate secretary at the address on the cover of this Form 10-K. Changes in and waivers to the Code of Conduct for the Company s directors, chief executive officer and certain senior financial officers will be posted on the Company s website within five business days and maintained for at least 12 months. 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.

ITEM 11. *EXECUTIVE COMPENSATION*

The information set forth under the captions Compensation Discussion and Analysis, Summary Compensation Table, Grants of Plan Based Awards Table, Outstanding Equity Awards at Fiscal Year-End Table, Option Exercises and Stock Vested Table, Non-Qualified Deferred Compensation Table, Employment Contracts and Termination of Employment and Change-in-Control Arrangements and Director Compensation Table in the Proxy Statement is incorporated herein by reference.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The information set forth under the captions Securities Ownership and Principal Holders and Equity Compensation Plan Information in the Proxy Statement is incorporated herein by reference.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information set forth under the captions Certain Business Relationships and Transactions and Director Independence in the Proxy Statement is incorporated herein by reference.

ITEM 14. ***PRINCIPAL ACCOUNTING FEES AND SERVICES***

The information set forth under the caption Independent Auditors in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a) Documents included in this report:

1. Financial Statements

Report of management	F-1
Report of independent registered public accounting firm	F-2
Report of independent registered public accounting firm	F-3
Statement of consolidated operations for each of the three years in the period ended December 31, 2013	F-4
Statement of consolidated comprehensive income for each of the three years in the period ended December 31, 2013	F-5
Statement of consolidated cash flows for each of the three years in the period ended December 31, 2013	F-6
Consolidated balance sheet as of December 31, 2013 and 2012	F-7
Statement of consolidated changes in equity for each of the three years in the period ended December 31, 2013	F-8
Notes to consolidated financial statements	F-9

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company s financial statements and related notes.

3. Exhibits

EXHIBIT NO.	DESCRIPTION
2.1	Agreement and Plan of Merger, dated April 14, 2010, by and among Registrant, ZMZ Acquisitions LLC, and Mariner Energy, Inc. (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K, dated April 14, 2010, filed April 16, 2010, SEC File No. 001-4300) (the schedules and annexes have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.2	Amendment No. 1, dated August 2, 2010, to Agreement and Plan of Merger, dated April 14, 2010, by and among Registrant, ZMZ Acquisitions LLC, and Mariner Energy, Inc. (incorporated by

	reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K, dated August 2, 2010, filed on August 3, 2010, SEC File No. 001-4300) (the schedules and annexes have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.3	Purchase and Sale Agreement by and between BP America Production Company and ZPZ Delaware I LLC dated July 20, 2010 (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No. 001-4300) (the exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.4	Partnership Interest and Share Purchase and Sale Agreement by and between BP Canada Energy and Apache Canada Ltd. dated July 20, 2010 (incorporated by reference to Exhibit 2.2 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No. 001-4300) (the exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K).

EXHIBIT NO.	DESCRIPTION
2.5	Purchase and Sale Agreement by and among BP Egypt Company, BP Exploration (Delta) Limited and ZPZ Egypt Corporation LDC dated July 20, 2010 (incorporated by reference to Exhibit 2.3 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No. 001-4300) (the exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
3.1	Restated Certificate of Incorporation of Registrant, dated September 19, 2013, as filed with the Secretary of State of Delaware on September 19, 2013 (incorporated by reference to Exhibit 3.2 to Registrant s Current Report on Form 8-K filed September 20, 2013, SEC File No. 001-4300).
3.2	Certificate of Designations of the 6.00% Mandatory Convertible Preferred Stock, Series D (incorporated by reference to Exhibit 3.3 to Registrant s Registration Statement on Form 8-A, dated July 29, 2010, SEC File No. 001-4300).
3.3	Certificate of Elimination of Series D Preferred Stock of Registrant, dated September 18, 2013, as filed with the Secretary of State of Delaware on September 19, 2013 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed September 19, 2013, SEC File No. 001-4300).
3.4	Bylaws of Registrant, as amended May 16, 2013 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed May 17, 2013, SEC File No. 001-4300).
4.1	Form of Certificate for Registrant s Common Stock (incorporated by reference to Exhibit 4.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, SEC File No. 001-4300).
4.2	Form of Certificate for the 6.00% Mandatory Convertible Preferred Stock, Series D (incorporated by reference to Exhibit A of Exhibit 3.3 to Registrant s Registration Statement on Form 8-A, dated July 29, 2010, SEC File No. 001-4300).
4.3	Form of 3.625% Notes due 2021 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.4	Form of 5.250% Notes due 2042 (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.5	Form of 5.100% Notes due 2040 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated August 17, 2010, filed on August 20, 2010, SEC File No. 001-4300).
4.6	Form of 1.75% Notes due 2017 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated April 3, 2012, filed on April 9, 2012, SEC File No. 001-4300).
4.7	Form of 3.25% Note due 2022 (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated April 3, 2012, filed on April 9, 2012, SEC File No. 001-4300).
4.8	Form of 4.75% Notes due 2043 (incorporated by reference to Exhibit 4.3 to Registrant s Current Report on Form 8-K, dated April 3, 2012, filed on April 9, 2012, SEC File No. 001-4300).
4.9	

	Form of 2.625% Notes due 2023 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated November 28, 2012, filed on December 4, 2012, SEC File No. 001-4300).
4.10	Form of 4.250% Notes due 2044 (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated November 28, 2012, filed on December 4, 2012, SEC File No. 001-4300).

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EXHIBIT NO.	DESCRIPTION
4.11	Rights Agreement, dated January 31, 1996, between Registrant and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.), rights agent, relating to the declaration of a rights dividend to Registrant s common shareholders of record on January 31, 1996 (incorporated by reference to Exhibit (a) to Registrant s Registration Statement on Form 8-A, dated January 24, 1996, SEC File No. 001-4300).
4.12	Amendment No. 1, dated as of January 31, 2006, to the Rights Agreement dated as of December 31, 1996, between Apache Corporation, a Delaware corporation, and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.) (incorporated by reference to Exhibit 4.4 to Registrant s Amendment No. 1 to Registration Statement on Form 8-A, dated January 31, 2006, SEC File No. 001-4300).
4.13	Senior Indenture, dated February 15, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank), formerly known as The Chase Manhattan Bank, as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.14	First Supplemental Indenture to the Senior Indenture, dated as of November 5, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.15	Form of Indenture among Apache Finance Pty Ltd, Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Registrant s Registration Statement on Form S-3, dated November 12, 1997, Reg. No. 333-339973).
4.16	Form of Indenture among Registrant, Apache Finance Canada Corporation and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to Registrant s Registration Statement on Form S-3, dated November 12, 1999, Reg. No. 333-90147).
4.17	Deposit Agreement, dated as of July 28, 2010, between Registrants and Wells Fargo Bank, N.A., as depositary, on behalf of all holders from time to time of the receipts issued there under (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated July 22, 2010, filed on July 28, 2010, SEC File No. 001-4300).
4.18	Form of Depositary Receipt for the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated July 22, 2010, filed on July 28, 2010, SEC File No. 001-4300).
4.19	Senior Indenture, dated May 19, 2011, between Registrant and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Corporation (incorporated by reference to Exhibit 4.14 to Registrant s Registration Statement on Form S-3, dated May 23, 2011,

Reg. No. 333-174429).

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EXHIBIT NO.	DESCRIPTION
4.20	Senior Indenture, dated May 19, 2011, among Apache Finance Pty Ltd, Apache Corporation, as guarantor, and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Finance Pty Ltd and the related guarantees (incorporated by reference to Exhibit 4.16 to Registrant s Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.21	Senior Indenture, dated May 19, 2011, among Apache Finance Canada Corporation, Apache Corporation, as guarantor, and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Finance Corporation and the related guarantees (incorporated by reference to Exhibit 4.20 to Registrant s Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.22	Form of Apache Corporation November 10, 2010 First Non-Qualified Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).
4.23	Form of Apache Corporation November 10, 2010 Second Non-Qualified Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).
4.24	Form of Apache Corporation November 10, 2010 Non-Statutory Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.8 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).
10.1	Credit Agreement, dated August 12, 2011, among Registrant, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and Citibank, N.A., Bank of America, N.A., and Wells Fargo Bank, National Association, as Syndication Agents (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed August 18, 2011, SEC File No. 001-4300).
10.2	First Amendment to Credit Agreement, dated as of July 17, 2013, among Apache Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents party thereto, amending Credit Agreement, dated as of August 12, 2011, among the same parties (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, SEC File No. 001-4300).
10.3	Credit Agreement, dated as of June 4, 2012, among Apache Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Bank of America, N.A. and Citibank, N.A., as Global Syndication Agents, and The Royal Bank of Scotland plc and Royal Bank of Canada, as Global Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed June 7, 2012, SEC File No. 001-04300).
10.4	Credit Agreement, dated as of June 4, 2012, among Apache Canada Ltd., the lenders party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Royal Bank of Canada, as Canadian Administrative Agent, Bank of America, N.A. and Citibank, N.A., as Global Syndication Agents, and The Royal Bank of Scotland plc and Royal Bank of Canada, as Global Documentation Agents (incorporated by reference to Exhibit 10.2 to Registrant s Current Report on Form 8-K filed June 7, 2012, SEC File No. 001-04300)

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EXHIBIT

NO.	DESCRIPTION
10.5	Syndicated Facility Agreement, dated as of June 4, 2012, among Apache Energy Limited (ACN 009 301 964), the lenders party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Citisecurities Limited (ABN 51 008 489 610), as Australian Administrative Agent, Bank of America, N.A. and Citibank, N.A., as Global Syndication Agents, and The Royal Bank of Scotland plc and Royal Bank of Canada, as Global Documentation Agents (incorporated by reference to Exhibit 10.3 to Registrant s Current Report on Form 8-K filed June 7, 2012, SEC File No. 001-04300).
10.6	Apache Corporation Corporate Incentive Compensation Plan A (Senior Officers Plan), dated July 16, 1998 (incorporated by reference to Exhibit 10.13 to Registrant s Annual Report on Form 10-K for year ended December 31, 1998, SEC File No. 001-4300).
10.7	First Amendment to Apache Corporation Corporate Incentive Compensation Plan A, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.17 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.8	Apache Corporation Corporate Incentive Compensation Plan B (Strategic Objectives Format), dated July 16, 1998 (incorporated by reference to Exhibit 10.14 to Registrant s Annual Report on Form 10-K for year ended December 31, 1998, SEC File No. 001-4300).
10.9	First Amendment to Apache Corporation Corporate Incentive Compensation Plan B, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.19 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
* 10.10	Apache Corporation 401(k) Savings Plan, as amended and restated, dated May 14, 2013, effective May 1, 2013.
10.11	Amendment to Apache Corporation 401(k) Savings Plan, dated October 25, 2013 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, SEC File No. 001-4300).
10.12	Non-Qualified Retirement/Savings Plan of Apache Corporation, as amended and restated July 14, 2010, except as otherwise specified (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, SEC File No. 001-4300).
10.13	Amendment to Apache Corporation Non-Qualified Retirement/Savings Plan of Apache Corporation, dated December 19, 2011, effective January 1, 2012 (incorporated by reference to Exhibit 10.20 to Registrant s Annual Report Form 10-K for year ended December 31, 2011, SEC File No. 001-4300).
10.14	Amendment to Non-Qualified Retirement/Savings Plan of Apache Corporation, dated November 8, 2012, effective January 1, 2013 (incorporated by reference to Exhibit 10.25 to Registrant s Annual Report on Form 10-K for year ended December 31, 2012, SEC File No. 001-4300).
10.15	Non-Qualified Restorative Retirement Savings Plan of Apache Corporation, dated November 7, 2011, effective January 1, 2012 (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-8, dated December 21, 2011, Reg. No. 333-178672).
10.16	Amendment to Non-Qualified Restorative Retirement Savings Plan of Apache Corporation, dated November 8, 2012, effective January 1, 2013 (incorporated by reference to Exhibit 10.27 to Registrant s Annual Report on Form 10-K for year ended December 31, 2012, SEC File No. 001-4300).

EXHIBIT

NO.	DESCRIPTION
* 10.17	Apache Corporation 2011 Omnibus Equity Compensation Plan, as amended and restated February 3, 2014.
10.18	Apache Corporation 2007 Omnibus Equity Compensation Plan, as amended and restated May 4, 2011 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, SEC File No. 001-4300).
10.19	Apache Corporation 2000 Stock Option Plan, as amended and restated May 5, 2011 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, SEC File No. 001-4300).
10.20	Apache Corporation 2003 Stock Appreciation Rights Plan, as amended and restated September 16, 2013 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2013, SEC File No. 001-4300).
10.21	Apache Corporation 2005 Stock Option Plan, as amended and restated September 16, 2013 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2013, Commission File No. 001-4300).
10.22	Apache Corporation Income Continuance Plan, as amended and restated July 14, 2010, effective January 1, 2009 (incorporated by reference to Exhibit 10.5 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, SEC File No. 001-4300).
* 10.23	Apache Corporation Deferred Delivery Plan, as amended and restated November 11, 2013.
10.24	Apache Corporation Non-Employee Directors Compensation Plan, as amended and restated February 6, 2013 (incorporated by reference to Exhibit 10.39 to Registrant s Annual Report on Form 10-K for the year ended December 31, 2012, SEC File No. 001-4300).
10.25	Apache Corporation Outside Directors Retirement Plan, as amended and restated February 6, 2013 (incorporated by reference to Exhibit 10.40 to Registrant s Annual Report on Form 10-K for the year ended December 31, 2012, SEC File No. 001-4300).
10.26	Apache Corporation Equity Compensation Plan for Non-Employee Directors, as amended and restated February 8, 2007 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2007, SEC File No. 001-4300).
10.27	Apache Corporation Non-Employee Directors Restricted Stock Units Program Specifications, dated May 5, 2011, pursuant to Apache Corporation 2011 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.6 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, SEC File No. 001-4300).
* 10.28	Apache Corporation Non-Employee Directors Restricted Stock Units Program Specifications, as amended and restated May 15, 2013, pursuant to Apache Corporation 2011 Omnibus Equity Compensation Plan.
10.29	Restated Employment and Consulting Agreement, dated January 15, 2009, between Registrant and Raymond Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K, dated January 15, 2009, filed January 16, 2009, SEC File No. 001-4300).
10.30	

	Amended and Restated Employment Agreement, dated December 20, 1990, between Registrant and John A. Kocur (incorporated by reference to Exhibit 10.10 to Registrant s Annual Report on Form 10-K for year ended December 31, 1990, SEC File No. 001-4300).
10.31	Employment Agreement between Registrant and G. Steven Farris, dated June 6, 1988, and First Amendment, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.44 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).

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EXHIBIT NO.	DESCRIPTION
10.32	Restricted Stock Unit Award Agreement, dated May 8, 2008, between Registrant and G. Steven Farris (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2008, SEC File No. 001-4300).
10.33	Form of Restricted Stock Unit Award Agreement, dated February 12, 2009, between Registrant and each of John A. Crum, Rodney J. Eichler, and Roger B. Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K, dated February 12, 2009, filed February 18, 2009, SEC File No. 001-4300).
10.34	Amendment to Restricted Stock Unit Award Agreement, dated March 7, 2011, between Registrant and John A. Crum (incorporated by reference to Exhibit 10.1 to Registrant s Current Report Form 8-K/A filed March 8, 2011, SEC File No. 001-4300).
10.35	Resignation Agreement, dated March 7, 2011 between Registrant and John A. Crum (incorporated by reference to Exhibit 10.2 to Registrant s Current Report on Form 8-K/A filed March 8, 2011, SEC File No. 001-4300).
10.36	Form of Restricted Stock Unit Award Agreement, dated November 18, 2009, between Registrant and Michael S. Bahorich (incorporated by reference to Exhibit 10.37 to Registrant s Annual Report on Form 10-K for year ended December 31, 2009, SEC File No. 001-4300).
10.37	Form of Restricted Stock Unit Grant Agreement, dated May 6, 2009, between Registrant and each of G. Steven Farris, Roger B. Plank, John A. Crum, Rodney J. Eichler, and Michael S. Bahorich (incorporated by reference to Exhibit 10.38 to Registrant s Annual Report on Form 10-K for year ended December 31, 2009, SEC File No. 001-4300).
10.38	Form of Stock Option Award Agreement, dated May 6, 2009, between Registrant and each of G. Steven Farris, Roger B. Plank, John A. Crum, Rodney J. Eichler, and Michael S. Bahorich (incorporated by reference to Exhibit 10.39 to Registrant s Annual Report on Form 10-K for year ended December 31, 2009, SEC File No. 001-4300).
10.39	Form of 2010 Performance Program Agreement, dated January 15, 2010, between Registrant and each of G. Steven Farris, John A. Crum, Rodney J. Eichler, and Roger B. Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed January 19, 2010, SEC File No. 001-4300).
10.40	Form of First Amendment, effective May 5, 2010, to 2010 Performance Program Agreement, dated January 15, 2010, between Registrant and each of G. Steven Farris, John A. Crum, Rodney J. Eichler, and Roger B. Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed May 11, 2010, SEC File No. 001-4300).
10.41	Form of Restricted Stock Unit Award Agreement, dated January 15, 2010, between Registrant and each of John A. Crum, Rodney J. Eichler, and Roger B. Plank (incorporated by reference to Exhibit 10.2 to Registrant s Current Report on Form 8-K filed January 19, 2010, SEC File No. 001-4300).
10.42	Form of 2011 Performance Program Agreement, dated January 7, 2011, between Registrant and each of G. Steven Farris, John A. Crum, Rodney J. Eichler, Roger B. Plank, Michael S. Bahorich, and Thomas P. Chambers (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed January 13, 2011, SEC File No. 001-4300).

10.43	Restricted Stock Unit Award Agreement, dated February 9, 2011, between Registrant and Thomas P. Chambers (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed February 14, 2011, SEC File No. 001-4300).
10.44	Form of 2012 Performance Program Agreement, dated January 11, 2012, between Registrant and each of G. Steven Farris, Rodney J. Eichler, Roger B. Plank, P. Anthony Lannie, and Thomas P. Chambers (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed January 13, 2012, SEC File No. 001-4300).

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EXHIBIT NO.	DESCRIPTION
10.45	Form of 2013 Performance Program Agreement, dated January 9, 2013, between Registrant and each of G. Steven Farris, Rodney J. Eichler, Roger B. Plank, and Thomas P. Chambers (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed January 11, 2013, SEC File No. 001-4300).
*10.46	Form of 2014 Performance Agreement (Total Shareholder Return), dated January 9, 2014, between Registrant and each of G. Steven Farris, Rodney J. Eichler, Roger B. Plank, P. Anthony Lannie, and Thomas P. Chambers.
*10.47	Form of 2014 Performance Agreement (Business Performance), dated February 3, 2014, between Registrant and each of G. Steven Farris, Roger B. Plank, Rodney J. Eichler, P. Anthony Lannie, and Thomas P. Chambers.
*12.1	Statement of Computation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends.
*14.1	Code of Business Conduct, as amended and restated November 13, 2013.
*21.1	Subsidiaries of Registrant
*23.1	Consent of Ernst & Young LLP
*23.2	Consent of Ryder Scott Company L.P., Petroleum Consultants
*24.1	Power of Attorney (included as a part of the signature pages to this report)
*31.1	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Executive Officer.
*31.2	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Financial Officer.
*32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Executive Officer and Principal Financial Officer.
*99.1	Report of Ryder Scott Company L.P., Petroleum Consultants
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Schema Document.
*101.CAL	XBRL Calculation Linkbase Document.
*101.LAB	XBRL Label Linkbase Document.
*101.PRE	XBRL Presentation Linkbase Document.
*101.DEF	XBRL Definition Linkbase Document.

* Filed herewith.
Management contracts or compensatory plans or arrangements required to be filed herewith pursuant to Item 15 hereof.

NOTE: Debt instruments of the Registrant defining the rights of long-term debt holders in principal amounts not exceeding 10 percent of the Registrant s consolidated assets have been omitted and will be provided to the Commission upon request.

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SIGNATURES

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

APACHE CORPORATION

/s/ G. STEVEN FARRIS
G. Steven Farris
Chairman of the Board, Chief Executive Officer, and President

Dated: February 28, 2014

POWER OF ATTORNEY

The officers and directors of Apache Corporation, whose signatures appear below, hereby constitute and appoint G. Steven Farris, P. Anthony Lannie, Alfonso Leon, Thomas P. Chambers, and Rebecca A. Hoyt, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this report and each of the undersigned does hereby ratify and confirm all that said attorneys shall do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ G. STEVEN FARRIS G. Steven Farris	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 28, 2014
/s/ THOMAS P. CHAMBERS Thomas P. Chambers	Senior Vice President, Finance (principal financial officer)	February 28, 2014
/s/ REBECCA A. HOYT Rebecca A. Hoyt	Vice President, Chief Accounting Officer and Controller (principal accounting officer)	February 28, 2014

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Name	Title	Date
/s/ RANDOLPH M. FERLIC Randolph M. Ferlic	Director	February 28, 2014
/s/ EUGENE C. FIEDOREK Eugene C. Fiedorek	Director	February 28, 2014
/s/ A.D. FRAZIER, JR. A. D. Frazier, Jr.	Director	February 28, 2014
/s/ CHANSOO JOUNG Chansoo Joung	Director	February 28, 2014
/s/ GEORGE D. LAWRENCE George D. Lawrence	Director	February 28, 2014
/s/ JOHN E. LOWE John E. Lowe	Director	February 28, 2014
/s/ WILLIAM C. MONTGOMERY William C. Montgomery	Director	February 28, 2014
/s/ AMY H. NELSON Amy H. Nelson	Director	February 28, 2014
/s/ RODMAN D. PATTON Rodman D. Patton	Director	February 28, 2014
/s/ CHARLES J. PITMAN Charles J. Pitman	Director	February 28, 2014

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REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for the preparation and integrity of the consolidated financial statements appearing in this annual report on Form 10-K. The financial statements were prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management s best estimates and judgments.

Management of the Company is responsible for establishing and maintaining effective internal control over financial reporting as such term is defined in Rule 13a-15(f) under the Securities Exchange Act of 1934. The Company s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by a program of internal audits and appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by our Company s board of directors, applicable to all Company directors and all officers and employees of our Company and subsidiaries.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework (1992).* Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2013.

The Company s independent auditors, Ernst & Young LLP, a registered public accounting firm, are appointed by the Audit Committee of the Company s board of directors. Ernst & Young LLP have audited and reported on the consolidated financial statements of Apache Corporation and subsidiaries, and the effectiveness of the Company s internal control over financial reporting. The reports of the independent auditors follow this report on pages F-2 and F-3.

/s/ G. Steven Farris

Chairman of the Board, Chief Executive Officer, and President

(principal executive officer)

/s/ Thomas P. Chambers

Senior Vice President, Finance

(principal financial officer)

/s/ Rebecca A. Hoyt

Vice President, Chief Accounting Officer and Controller

(principal accounting officer)

Houston, Texas

February 28, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Apache Corporation:

We have audited the accompanying consolidated balance sheets of Apache Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Apache Corporation and subsidiaries at December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Apache Corporation s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 28, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Apache Corporation:

We have audited Apache Corporation and subsidiaries internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Apache Corporation and subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Apache Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Apache Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2013 of Apache Corporation and subsidiaries, and our report dated February 28, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2014

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APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31, 2013	2012	2011
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil and gas production revenues:			
Oil revenues	$ 12,903	$ 13,210	$ 12,679
Gas revenues	2,829	3,193	3,609
Natural gas liquids revenues	670	544	522
	16,402	16,947	16,810
Derivative instrument gains (losses), net	(399)	(79)	
Other	51	210	78
	16,054	17,078	16,888
OPERATING EXPENSES:			
Depreciation, depletion, and amortization:			
Oil and gas property and equipment			
Recurring	5,114	4,812	3,814
Additional	1,176	1,926	109
Other assets	410	371	281
Asset retirement obligation accretion	243	232	154
Lease operating expenses	3,056	2,968	2,605
Gathering and transportation	297	303	296
Taxes other than income	832	862	899
General and administrative	503	531	459
Acquisitions, divestitures and transition	33	31	20
Financing costs, net	174	165	158
	11,838	12,201	8,795
INCOME BEFORE INCOME TAXES	4,216	4,877	8,093
Current income tax provision	1,665	2,199	2,263
Deferred income tax provision	263	677	1,246
NET INCOME INCLUDING NONCONTROLLING INTEREST	2,288	2,001	4,584
Net income attributable to noncontrolling interest	56		
Preferred stock dividends	44	76	76
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 2,188	$ 1,925	$ 4,508
NET INCOME PER COMMON SHARE:			
Basic	$ 5.53	$ 4.95	$ 11.75
Diluted	$ 5.50	$ 4.92	$ 11.47
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	395	389	384
Diluted	406	391	400