APACHE CORP
Form 10-K
March 01, 2013

# 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, 2012**

**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 | New York Stock Exchange |

| | |
|---|---|
| Guaranteed by Apache Corporation | |
| Depositary Shares Representing a 1/20th | New York Stock Exchange |
| Interest in a Share of 6.00% Mandatory | |
| Convertible Preferred Stock, Series D | |

**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, 2012 | $ 34,382,410,237 |
| Number of shares of registrant s common stock outstanding as of January 31, 2013 | 391,758,883 |

**Documents Incorporated By Reference**

Portions of registrant s proxy statement relating to registrant s 2013 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

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### DESCRIPTION

## 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.

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.

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.

## 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 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 7, 2012, 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:

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

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 27 years and production 32 out of the past 34 years, a testament to our consistency over the long-term.

Apache pursues opportunities for growth through exploration and development drilling, supplemented by occasional strategic acquisitions. After a three-year period of significant portfolio expansion through acquisitions, we have shifted our focus back to developing our enlarged property base. In 2012, we generated approximately $8.5 billion of cash flows from operating activities, which enabled us to have an active drilling and development program across all of our regions. As a result, we reported record production of 779 Mboe/d, up over four percent from the prior year. At the same time, we have also invested a larger portion of our capital budget on long-lead time projects than we have in the past. In 2012, we spent approximately one-quarter of our capital budget on purchasing additional leasehold acreage, obtaining seismic data, building infrastructure, and proceeding on long-lead development projects including LNG facilities. Coupled with an active drilling program and our new venture exploration efforts, these longer-term investments secure a platform for future profitable growth.

While we are focused on growth through the drill bit, we also seek acquisition opportunities that meet our criteria for risk, reward, rate of return, and growth potential. From April 2010 through the end of 2012, Apache announced several significant acquisitions, each of which fit well with our long-term growth strategy. These properties are strategically positioned with our existing infrastructure and play to the strengths that come with our operating experience. Our significant acquisitions and other transactions since 2010 are described below.

***2012 Transactions***

*Chevron Kitimat transaction* On December 24, 2012, Chevron Canada Limited (Chevron Canada) and Apache Canada Ltd. (Apache Canada) entered into an agreement to build and operate the Kitimat LNG project. Pursuant to the agreement, each will become a 50-percent owner of the proposed Kitimat LNG plant, the Pacific Trail Pipeline, and 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant, which will be located on the northern British Columbia coast, and the pipeline; Apache Canada will operate Horn River and Liard. The transaction closed on February 8, 2013.

*Central Anadarko basin acquisition* In April 2012 Apache completed the acquisition of Cordillera Energy Partners III, LLC (Cordillera), a privately held company, for $2.7 billion in cash and approximately 6.3 million shares of Apache common stock.

*Yara Pilbara Holdings Pty Limited 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. YPHPL is the owner of an ammonia fertilizer plant on the Burrup Peninsula of Western Australia.

***2011 Transactions***

*North Sea acquisition* On December 30, 2011, Apache completed the acquisition of Mobil North Sea Limited (Mobil North Sea) from Exxon Mobil Corporation with cash consideration of $1.25 billion.

***2010 Transactions***

*Gulf of Mexico Shelf acquisition* On June 9, 2010, Apache completed the acquisition of oil and gas assets in the Gulf of Mexico shelf from Devon Energy Corporation for $1.05 billion.

*Permian acquisition* On August 10, 2010, we completed the acquisition of BP plc s (BP) oil and gas operations, acreage, and infrastructure in the Permian Basin for $2.5 billion, net of preferential rights to purchase.

*Canadian acquisition* On October 8, 2010, we completed the acquisition of substantially all of BP s upstream natural gas business in western Alberta and British Columbia for $3.25 billion.

*Egyptian acquisition* On November 4, 2010, we completed the acquisition of BP s assets in Egypt s Western Desert for $650 million.

*Mariner merger* On November 10, 2010, Apache completed the acquisition of Mariner Energy, Inc. (Mariner) for stock and cash consideration totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt with the merger.

For a more in-depth discussion of our growth strategy, 2012 results, and the Company s capital resources and liquidity, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

**Geographic Area Overviews**

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 table sets out a brief comparative summary of certain key 2012 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

| | 2012 Production (In MMboe) | Percentage of Total 2012 Production | 2012 Production Revenue (In millions) | 12/31/12 Estimated Proved Reserves (In MMboe) | Percentage of Total Estimated Proved Reserves | 2012 Gross Wells Drilled | 2012 Gross Productive Wells Drilled |
|---|---|---|---|---|---|---|---|
| United States | 113.5 | 40% | $ 6,226 | 1,424 | 50% | 1,052 | 1,035 |
| Canada | 44.7 | 16 | 1,322 | 541 | 19 | 169 | 145 |
| Total North America | 158.2 | 56 | 7,548 | 1,965 | 69 | 1,221 | 1,180 |
| Egypt | 58.1 | 20 | 4,554 | 273 | 10 | 198 | 174 |
| Australia | 23.6 | 8 | 1,575 | 342 | 12 | 15 | 8 |
| North Sea | 27.4 | 10 | 2,751 | 170 | 6 | 21 | 16 |
| Argentina | 17.7 | 6 | 519 | 102 | 3 | 30 | 30 |
| Other International | | | | | | 1 | |
| Total International | 126.8 | 44 | 9,399 | 887 | 31 | 265 | 228 |
| Total | 285.0 | 100% | $ 16,947 | 2,852 | 100% | 1,486 | 1,408 |

***North America***

Apache s North American asset base primarily comprises operations in the central U.S., the Permian Basin, the Gulf Coast onshore and offshore areas of the U.S., and operations in Western Canada. In 2012, our North America assets contributed 56 percent of our production and 45 percent of our oil and gas production revenues. At year-end 2012, 69 percent of our estimated proved reserves were located in North America.

*United States*

*Overview* We have 12.3 million gross acres across the U.S., approximately 60 percent of which is undeveloped. After expanding our portfolio over the last three years, we now hold leading positions in many attractive basins and plays within the United States. To focus our development efforts in the U.S., we have divided our assets into five distinct regions: Central, Permian, Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore. We also have leasehold acreage holdings in Alaska and other states where we are pursuing exploration opportunities. Our holdings in the U.S. provide a balance of hydrocarbon mix and reserve life and an opportunity for continued exploration. In 2012, 54 percent of our U.S. production and 63 percent of our U.S. year-end estimated proved reserves were oil and liquids. In addition, the reserve life of our U.S. regions ranged from 6 to 20 years with the Gulf of Mexico offshore region s shorter-lived reserves balancing longer-lived reserves in the Central and Permian regions. In 2012, 40 percent of Apache s equivalent production and 50 percent of Apache s total year-end estimated proved reserves were in the U.S.

*Central Region* The Central region includes more than 3,500 producing wells primarily in western Oklahoma and the Texas panhandle and controls nearly 1.9 million gross acres. The region is Apache s first core area dating back over half a century and has historically grown through low-risk, highly predictable natural gas exploitation. Over the last three years, however, a transformation from vertical to horizontal drilling and continued price disparity between crude oil and natural gas have evolved the region from one targeting natural gas to one now targeting oil and liquids-rich gas plays. This focus resulted in liquids production growth of over 115 percent during 2011. Oil and liquids production further expanded during 2012, with oil production more than doubling and NGL production almost tripling compared to the prior year. Total region production was up 37 percent in 2012. The Central region contributed 8 percent of Apache s 2012 equivalent production and 9 percent of total year-end proved reserves.

The primary driver of the region s growth was an active exploration and development program where we drilled or participated in drilling 192 wells during 2012, 99 percent of which were completed as producers. A significant focus of our drilling program has been in the Anadarko basin s Granite Wash play. The Granite Wash consists of a series of thick, multi-layered formations of low-permeability and liquids-rich sandstones. The Company s significant acreage position in the play has generated an active drilling plan for the next several years across numerous formations, notably the Tonkawa, Marmaton, Cottage Grove, and Cleveland.

We have also been drilling Canyon Wash wells on approximately 92,000 net acres in the Whittenburg basin. During the year, we drilled and completed seven successful wells in the Canyon Wash, which averaged 30-day gross rates of approximately 675 b/d and 500 Mcf/d. These tests are an encouraging validation of this play, given the results are from vertically drilled wells.

Our drilling momentum in the Central region was further bolstered in April when the Company completed the acquisition of Cordillera, a privately held company with approximately 312,000 net acres in the heart of the Anadarko basin, nearly 18 Mboe/d of production, and estimated proved reserves of 70 MMboe. The acquisition doubled Apache s acreage in the Granite Wash area and added a robust drilling inventory that was immediately integrated into our existing program.

The region operated an average of 18 drilling rigs during 2012 and, with a growing portfolio of drilling opportunities, plans to run an average of 29 rigs during 2013. We expect to invest approximately $1.4 billion in 2013 for drilling, recompletions, equipment upgrades, and production enhancement projects. The region will also invest in facility and transportation projects to increase takeaway capacity.

*Permian Region* Our Permian region controls over 3.5 million gross acres with exposure across every major play in the Permian Basin. The region s property and acreage base has increased substantially over the last three years through an active acquisition effort. Apache is now one of the largest operators in the Permian Basin, operating more than 12,000 wells in 152 fields, including 47 waterfloods and 7 active $CO_2$ floods, including the Roberts Unit, which initiated $CO_2$ injection in January 2013. In 2012, liquids production in the region was up 25 percent, contributing to a total sequential production increase of over 18 percent as a result of an active drilling program that is continuing to ramp up. We averaged running 32 rigs during the year, drilling or participating in 781 wells, and plan to run 34 rigs in 2013. The Permian region s year-end 2012 estimated proved reserves were 800 MMboe and represented 28 percent of Apache s total proved reserves.

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

16 rigs and drilled 317 wells. Specifically, the region is primarily drilling vertical wells targeting the Wolfwood and the Fusselman zones. With additional 3-D seismic data recently acquired, our ability to target other prolific accumulations and new drilling locations has been enhanced.

The region is also building a large inventory of horizontal drilling opportunities based on success achieved over 2012, having drilled or participated in drilling 104 horizontal wells during the period. Two horizontal plays in the Midland Basin, the Wolfcamp and Cline shales, have been drilled and commercialized with multi-rig development programs moving forward. Also in the Midland Basin, we recently drilled and completed oil-producing wells in the Barnett and Deadwood shales focusing on the future potential across our large acreage position. New horizontal plays in the Mississippian Lime and Clearfork shales are planned for 2013. We recently commenced horizontal well programs in the Yeso area of New Mexico as well as in the Bone Spring and Wolfcamp plays in Texas. We also continue to achieve positive results in the Central basin with horizontal redevelopment of historically conventional fields and reservoirs. We expect to conduct greater horizontal drilling into 2013, when we project that nearly half of our rigs will be drilling horizontal wells by year-end.

Our active drilling program has resulted in production growth for the past eight sequential quarters, rising 37 percent over the past two years. Given a current inventory of over 34,000 locations, the region has a deep portfolio of drilling opportunities for multiple years. For 2013, the Permian region plans to invest approximately $2.4 billion in drilling, recompletion projects, equipment upgrades, expansion of existing facilities and equipment, and leasing activities.

*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. The area is divided into three regions, which include the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore.

In water depths less than 500 feet, which constitutes most of our Gulf of Mexico Shelf region, Apache is currently the largest producer and has been the largest offshore held-by-production acreage owner since 2004, holding approximately three million gross acres. The region contributed 12 percent of our worldwide production and revenue during 2012. With prolific wells, strong cash flows, and a strategic position near the petrochemical-industrial complex on the U.S. Gulf Coast, the region has consistently generated high rates of return. During 2012 the region drilled or participated in 36 wells with an 80-percent success rate, consistent with activity levels of the prior two years. In June 2012, the region also participated in the federal lease sale where we were awarded 60 blocks, opening up additional exploration and development opportunities.

In water depths greater than 500 feet, the Gulf of Mexico Deepwater region is a relatively underexplored and oil prone area that provides exposure to significant reserve and production potential. Apache s strategic presence in the area was gained through the 2010 Mariner merger and was extended through our participation in the June 2012 federal lease sale where we were awarded 28 new leases. The Company now owns approximately 900,000 gross acres across 166 blocks as of the end of 2012. The Deepwater region contributed only 2 percent of Apache s worldwide production in 2012; however, there are several large projects and developments underway that could spur significant growth. The non-operated Lucius project, where Apache holds an 11.7-percent working interest, is currently under development with first production projected for 2014. In addition, the large-scale non-operated Heidelberg project continues to move forward. Apache has a 12.5-percent working interest in this development with first production projected for 2016. The region also continues to increase its exploration activity. After drilling two wells in 2011, we drilled five wells in 2012 with a 60-percent success rate. Seven wells are planned for drilling in the areas in which we hold an interest during 2013.

Apache s Gulf Coast Onshore region includes mature onshore and near-shore basins of Texas, Louisiana, and Mississippi, where it has a significant acreage position of approximately 1.4 million gross acres, including 330,000 mineral fee acres. With advancements in modern seismic imaging, horizontal drilling and completion technologies, additional opportunities continue to evolve. During the year, the region focused on drilling shallow and moderate-depth targets, increasing acreage holdings, and expanding regional 3-D seismic databases. In addition, the region continued evaluating several unconventional resource plays and deeper exploitation opportunities. The region drilled or participated in drilling 35 wells during 2012 and plans to drill or participate in approximately 39 wells in 2013.

In 2013, Apache plans to invest approximately $700 million, $400 million, and $250 million in the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore regions, respectively. The capital will be spent on drilling, recompletion and development projects, equipment upgrades, production enhancement projects, and seismic and lease activities. The Company spent $435 million on abandonment activities in 2012 over the entire Gulf Coast area and expects similar activity levels in 2013.

*U.S. Marketing* In general, most of our U.S. gas is sold at either monthly or daily market prices. Our natural gas is sold primarily to local distribution companies (LDCs), utilities, end-users, and integrated major oil companies. We maintain a diverse customer 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. Our objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices.

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

*Canada*

*Overview* Since entering the Canadian market in 1995, Apache has continued to increase its presence in the region and now holds approximately seven 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 opportunity. Canada represented approximately 19 percent of Apache s worldwide proved reserves at year-end 2012 and approximately 16 percent of 2012 worldwide production.

In 2012, Apache drilled or participated in drilling 169 wells in Canada, with a continued focus on increasing oil and liquids-rich gas production. Reservoir modeling and state-of-the-art horizontal drilling technology advanced several oil plays in the Viking, Glauconite, Dunvegan, and Sparky formations, and success with multi-stage fracture completions continues to increase the scope of oil and liquids-rich gas drilling opportunities.

Future natural gas drilling activity will be driven by market prices and the Kitimat LNG project. In December 2012, Apache announced an agreement with Chevron Canada to build and operate the Kitimat LNG project and develop shale gas resources at the Liard and Horn River basins in British Columbia. Chevron Canada and Apache Canada will each hold a 50-percent interest in the Kitimat LNG plant, the Pacific Trail Pipeline, and approximately 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant and pipeline, and Apache Canada will operate Horn River and Liard. 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. The transaction was completed on February 8, 2013.

In 2013, the region plans to invest approximately $680 million in drilling and development projects, equipment upgrades, production enhancement projects, seismic acquisition, and Kitimat project development. Drilling in 2013 will continue to focus on conventional oil and liquids-rich gas plays.

*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 via firm transportation contracts to export border points for delivery into Washington, California, and the Chicago area. We sell the majority of our Canadian gas on a monthly basis at either first-of-the-month or daily AECO index prices.

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 negotiated differential. We maximize the value of our condensate and heavier crudes by determining whether to blend the condensate into our own crude production or sell it in the market as a segregated product. The crude is transported on pipeline or truck within Western Canada to the market hubs in Alberta and Manitoba where it is sold, allowing for a more diversified group of purchasers and a higher netback price.

The region s NGL production is sold under contracts with prices based on market indices, 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 2012, international assets contributed 44 percent of our production and 55 percent of our oil and gas revenues. At year-end 2012, 31 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. Today we control 9.7 million gross acres, making Apache the largest acreage holder in Egypt s Western Desert. Only 18 percent of our gross acreage in Egypt has been developed, with gross production of 213 Mb/d and 900 MMcf/d in 2012, or 100 Mb/d and 354 MMcf/d net to Apache. The remaining 82 percent of our acreage is undeveloped, providing us with considerable exploration and development opportunities for the future. In 2012, the region contributed 27 percent of Apache s worldwide production revenue, 20 percent of our worldwide production, and 10 percent of our year-end 2012 estimated proved reserves. Our estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country share reserves.

Our operations in Egypt are conducted pursuant to production-sharing agreements in 23 separate concessions, under which the contractor partner pays all operating and capital expenditure costs for exploration and development. Development leases within concessions generally have a 25-year life, with extensions possible for additional commercial discoveries or on a negotiated basis, and currently have expiration dates ranging from five to 25 years. 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 Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis.

Historically, growth in Egypt has been driven by an ongoing drilling program, and we are one of the most active drillers in the region. Throughout 2012, we averaged running 25 rigs and drilled 188 development and injection wells and 51 exploration wells. Approximately 55 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 our ability to acquire and evaluate 3-D seismic surveys that enable the region s technical teams to consistently high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic reservoirs.

Heading into 2013, the region will continue an active drilling program and plans to invest approximately $1.1 billion for drilling, recompletion projects, development projects, and seismic acquisition. There are also several key infrastructure projects underway that will focus on maintaining gas deliverability and bringing additional liquids to market.

*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. Apache previously agreed to accept the industry-pricing formula on a majority of gas sold but retained the previous gas-price formula (without an oil price cap) until the end of 2012 for up to 100 MMcf/d gross. The region averaged $3.90 per Mcf in 2012.

Oil from the Khalda Concession, the Qarun Concession, and other nearby Western Desert blocks is sold to third parties in the Mediterranean 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 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 December 2012 the people of Egypt ratified a new constitution. Under the new constitution, the government must hold elections for the lower house of parliament within 60 days. 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 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 $1 billion of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $263 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.

*Australia*

*Overview* Apache s holdings in Australia are focused offshore Western Australia in the Carnarvon, Exmouth, and Browse basins. We have operated in the Carnarvon basin since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993. Production operations are located in the Carnarvon and Exmouth basins. In total, we control approximately 7.9 million gross acres offshore Western Australia through 30 exploration permits, 17 production licenses, and 13 retention leases. Approximately 90 percent of our acreage is undeveloped, and the region continues to actively pursue additional acreage opportunities.

During 2012, the region had net production of 29 Mb/d of oil and 214 MMcf/d of natural gas, contributing 9 percent of Apache s worldwide production revenue, 8 percent of worldwide production and 12 percent of year-end estimated proved reserves. Production compared to the prior year was 7 percent lower primarily as a result of natural decline in the Pyrenees and Van Gogh oil fields. Offsetting production declines was a full year of production from the Reindeer field. This gas is processed through the Devil Creek Gas Plant, which came online in December 2011. This plant is Western Australia s third domestic natural gas processing hub and the first new hub to be constructed in more than 15 years. Gas from the development has been sold to a number of customers in Western Australia s growing mining and minerals processing sectors at prices significantly higher than prior year realizations.

The region is a key component of Apache s exploration program. During 2012, we participated in drilling 15 offshore wells, of which 10 were exploration or appraisal wells. This compares to nine wells drilled in 2011. 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 onstream in the coming years.

First production is projected in 2013 from four completed gas wells in the Macedon gas field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant being built at Ashburton North in Western Australia. Apache has successfully marketed nearly all of its proved reserves in the Macedon field under long-term contracts at prices significantly higher than current realizations. We have a 29-percent non-operating working interest in the field and gas plant.

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 Floating Production Storage and Offloading Vessel (FPSO) at Van Gogh. To more effectively control the Van Gogh and Coniston field operations, development, and maintenance efforts, this FPSO (the Ningaloo Vision) was purchased from the lessor in January 2012. To accommodate production from Coniston, the FPSO is scheduled to go offline to the shipyard in early 2014 to complete required modifications.

The region will also continue development of the offshore Balnaves field, an oil accumulation located near the Brunello gas field offshore Western Australia. The project is expected to deliver initial gross production of 30 Mb/d in 2014 utilizing a leased FPSO vessel. Apache has a 65-percent working interest in the project.

Further advances were made on the region s largest development effort, which is the Chevron-operated Wheatstone LNG project (Wheatstone) in Western Australia. 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 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 2013, the region plans to invest approximately $1.9 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition. Approximately $1.5 billion of our 2013 capital will be invested in long-lead development projects.

*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, 2012, Apache had 21 active gas contracts in Australia with expiration dates ranging from

July 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 West Texas Intermediate (WTI)-based prices.

During 2011, advances were made on Wheatstone, with binding Sales and Purchase Agreements signed by two Asian customers for the delivery of approximately 60 percent of Apache s net LNG offtake. In 2012, further advances were made on the Wheatstone project with the signing of two non-binding Heads of Agreements, which will take the total committed delivery volumes to over 80 percent once the final binding Sales and Purchase Agreements are signed. These binding Sales and Purchase Agreements are expected to be finalized and signed in 2013.

*North Sea*

*Overview* Apache entered the North Sea in 2003 after acquiring an approximate 97-percent working interest in the Forties field (Forties). Since acquiring Forties, Apache has actively invested in the region, having produced and sold oil volumes in excess of the proved reserves initially recorded. This success spurred last year s Mobil North Sea Limited (Mobil North Sea) acquisition, which provided 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. During 2012, we also announced that the U.K. Department of Energy & Climate Change awarded the region 11 new operated licenses and 1 non-operated license, which together added approximately 613,000 gross acres to the region s portfolio. Included in these licenses is all of the available acreage adjacent to the Beryl field plus two key licenses near the Forties field.

In 2012, the North Sea region produced 64 Mb/d of oil and 57 MMcf/d of natural gas, contributing 16 percent of Apache s worldwide production revenue, 10 percent of worldwide production and 6 percent of year-end estimated proved reserves. The region s production was 36 percent higher compared to the prior year on production from the recently acquired Beryl assets and an active drilling program in both the Forties and Beryl fields. Drilling in the Forties field continued to benefit from extensive 4-D seismic interpretations obtained over the last two years and has targeted many areas of bypassed oil in the mature reservoir. A 3-D seismic survey of the Beryl field commenced in early August and, when completed, will further refine our drilling plans for these acquired assets. In 2012, 21 wells were drilled in the North Sea, of which 16 were productive. Two of the highest producing wells were the Beryl B72 well, which commenced production in May at a rate of 11.6 Mb/d and 13.1 MMcf/d, and the Beryl B73 well, which was completed in September with an initial rate of 8.2 Mb/d and 5.9 MMcf/d. Apache has a 55-percent net interest in the Beryl field as of year-end.

The region also made notable progress in several key development projects during the year. In April, production from the first Bacchus field well commenced at a peak rate of 6 Mb/d; in July, a second horizontal well was brought online at a peak rate of 9 Mb/d. Combined production from the two wells has been steady at 10 Mb/d since July. Apache s net interest is 50 percent. In September, the jacket for the Forties Alpha Satellite Platform was installed, with a topside and bridge scheduled to be delivered during the second quarter of 2013. This platform has been constructed to continue to exploit new opportunities at Forties and sits adjacent to the main Alpha platform. It will provide an additional 18 drilling slots beginning in the third quarter of 2013 along with power generation, fluid separation, gas lift compression, and oil export pumping.

In 2013, the region plans to invest approximately $900 million on a diverse set of capital projects. The region will continue to refine drilling programs associated with properties acquired in the Mobil North Sea acquisition and integrate the additional opportunities gained over the last year.

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

Natural gas from the Beryl field is processed through the SAGE gas plant operated by Apache. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The condensate mix from the SAGE plant is processed further downstream. The split streams of propane 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 currently has active operations in the provinces of Neuquén, Rio Negro, and Tierra del Fuego. We have interests in 32 concessions, exploration permits, and other interests totaling 4.4 million gross acres in four of the main Argentine hydrocarbon basins: Neuquén, Austral, Cuyo, and Noroeste. Our concessions have varying expiration dates ranging from two years to over 15 years remaining, subject to potential extensions. Apache is currently in the process of extending our concessions in the Tierra del Fuego and Rio Negro Provinces, which are scheduled to expire between 2015 and 2017. Future investment by Apache in the Tierra del Fuego and Rio Negro Provinces will be significantly influenced by the ability to extend the present concessions.

In 2012, Argentina produced 6 percent of our worldwide production and held 4 percent of our estimated proved reserves at year-end. We continue to focus our exploration and development activities in the Neuquén basin. During the year, the region drilled or participated in drilling 28 gross wells pursuant to a development drilling program that achieved a 100-percent success rate by focusing on unconventional Gas Plus gas and shallow oil plays. Our 2012 exploration program included drilling two gross horizontal wells targeting the Vaca Muerta shale formation, where we hold 1.3 million net acres, of which 586,000 net acres are in the oil play. In 2013, the region plans to finish testing and evaluating those wells in preparation for future drilling programs.

During 2013, the region plans to invest approximately $200 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

*Marketing*

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

- Gas Plus program: This program was instituted by the Argentine government in 2008 to encourage 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 2012, the average Gas Plus volume sold by Apache was 73.2 MMcf/d at an average price of $4.89 per Mcf. For 2013, Apache has signed contracts for total gross volumes to be sold under Gas Plus contracts of 80 MMcf/d at $5.01.

- 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 industry category. During 2012, we realized an average price of $0.84 per Mcf on government-regulated sales.

- Unregulated market: The majority of our remaining volumes are sold into the unregulated market. In 2012, realizations on sales in the unregulated market averaged $3.52 per Mcf.

The weighted average of government-regulated and unregulated sales for 2012 was $2.03 per Mcf.

*Crude Oil* Our crude oil is subject to an export tax, which effectively limits the prices buyers are willing to pay for domestic sales. Domestic oil prices are currently based on $42 per barrel, plus quality adjustments and local premiums, and producers realize a gradual increase or decrease as market prices deviate from the base price.

***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. The New Ventures group was established in 2010 with a worldwide program focused on deepwater exploration, where many of the world s large oil discoveries have occurred over the last decade, unconventional resources in North America and elsewhere, and underexplored basins that can be developed through application of new technologies.

Apache s 2012 activities included drilling in offshore Kenya; participating in the Suriname bid round and winning offshore block 53; establishing a presence in several known U.S. resource plays; and acquiring seismic and spudding our first well on our acreage in the Cook Inlet of Alaska. Apache s first exploration well in Kenya, the Mbawa 1, was drilled in the third quarter of 2012, encountering approximately 170 feet of natural gas pay in three zones. We have a 50-percent interest in the block and continue to analyze the well data to determine future exploration activities. In Alaska, the New Ventures team has acquired approximately 700,000 net acres over the last two years in the Cook Inlet basin and has commenced a robust seismic study over the area to facilitate future drilling activity. Apache has also leased nearly 500,000 net acres in the Mississippian Lime play in Kansas and Nebraska and 300,000 net acres in Montana s Williston basin. We have commenced drilling activity in both of these plays.

During 2013, we plan to invest approximately $100 million to further these projects and continue pursuing additional exploration opportunities.

**Major Customers**

In 2012, 2011, and 2010 purchases by Royal Dutch Shell plc and its subsidiaries accounted for 20 percent, 11 percent, and 15 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.

**Drilling Statistics**

Worldwide in 2012 we participated in drilling 1,486 gross wells, with 1,408 (95 percent) completed as producers. Historically, our drilling activities in the U.S. have generally concentrated on exploitation and extension of existing producing fields rather than exploration. As a general matter, our operations outside of the U.S. focus on a mix of exploration and development wells. In addition to our completed wells, at year-end several wells had not yet reached completion: 70 in the U.S. (55.73 net); 11 in Canada (9.00 net); 26 in Egypt (26.00 net); 2 in Australia (1.65 net); and 4 in Argentina (3.75 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 |
| **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 |
| **2010** | | | | | | | | | |
| United States | 3.7 | 2.2 | 5.9 | 309.2 | 12.7 | 321.9 | 312.9 | 14.9 | 327.8 |
| Canada | 6.5 | 1.5 | 8.0 | 122.3 | 5.7 | 128.0 | 128.8 | 7.2 | 136.0 |
| Egypt | 19.4 | 18.5 | 37.9 | 144.8 | 5.5 | 150.3 | 164.2 | 24.0 | 188.2 |
| Australia | 5.5 | 3.4 | 8.9 | 4.5 | 1.3 | 5.8 | 10.0 | 4.7 | 14.7 |
| North Sea | 1.0 | 1.2 | 2.2 | 10.7 | 5.8 | 16.5 | 11.7 | 7.0 | 18.7 |
| Argentina | 1.8 | 2.7 | 4.5 | 43.3 | 0.3 | 43.6 | 45.1 | 3.0 | 48.1 |
| Total | 37.9 | 29.5 | 67.4 | 634.8 | 31.3 | 666.1 | 672.7 | 60.8 | 733.5 |

**<u>Productive Oil and Gas Wells</u>**

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of December 31, 2012, is set forth below:

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| United States | 13,762 | 9,192 | 5,375 | 3,149 | 19,137 | 12,341 |
| Canada | 2,195 | 997 | 9,065 | 7,744 | 11,260 | 8,741 |
| Egypt | 977 | 937 | 79 | 74 | 1,056 | 1,011 |
| Australia | 49 | 25 | 13 | 8 | 62 | 33 |
| North Sea | 151 | 99 | 23 | 12 | 174 | 111 |
| Argentina | 474 | 397 | 417 | 383 | 891 | 780 |
| Total | 17,608 | 11,647 | 14,972 | 11,370 | 32,580 | 23,017 |

Gross natural gas and crude oil wells include 1,625 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 Lease Operating Cost per Boe | Average Sales Price | | |
|---|---|---|---|---|---|---|---|
| Year Ended December 31, | Oil (MMbbls) | NGLs (MMbbls) | Gas (Bcf) | | Oil (Per bbl) | NGLs (Per bbl) | Gas (Per Mcf) |
| **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 |
| **2010** | | | | | | | |
| United States | 35.3 | 5.0 | 266.8 | $ 11.40 | $ 76.13 | $ 41.45 | $ 5.28 |
| Canada | 5.3 | 1.1 | 144.5 | 13.46 | 72.83 | 36.61 | 4.48 |
| Egypt | 36.2 | | 136.8 | 5.56 | 79.45 | | 3.62 |
| Australia | 16.7 | | 72.9 | 6.41 | 77.32 | | 2.24 |
| North Sea | 20.8 | | 0.9 | 9.23 | 76.66 | | 18.64 |
| Argentina | 3.6 | 1.2 | 67.5 | 7.97 | 57.47 | 27.08 | 1.96 |
| Total | 117.9 | 7.3 | 689.4 | 9.20 | 76.69 | 38.58 | 4.15 |

**Gross and Net Undeveloped and Developed Acreage**

The following table sets out our gross and net acreage position as of December 31, 2012, in each country where we have operations:

| | Undeveloped Acreage | | Developed Acreage | |
|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres |
| United States | 7,447,487 | 4,896,442 | 4,873,810 | 2,609,338 |
| Canada | 2,659,323 | 2,328,842 | 4,278,252 | 3,226,076 |
| Egypt | 7,934,690 | 5,142,158 | 1,800,720 | 1,693,216 |
| Australia | 7,058,038 | 3,854,352 | 880,467 | 534,665 |
| North Sea | 563,129 | 245,729 | 159,961 | 94,448 |
| Argentina | 4,182,067 | 3,106,969 | 221,422 | 188,795 |
| Total | 29,844,734 | 19,574,492 | 12,214,632 | 8,346,538 |

As of December 31, 2012, we had 5,229,947, 1,940,328, and 2,596,636 net acres scheduled to expire by December 31, 2013, 2014, and 2015, respectively, if production is not established or we take no other action to extend the terms. We strive to continue 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.

As of December 31, 2012, 37 percent of U.S. net undeveloped acreage and 47 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.

The following table shows proved oil, NGL, and gas reserves as of December 31, 2012, based on average commodity prices in effect on the first day of each month in 2012, 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 | 474 | 155 | 2,354 | 1,021 |
| Canada | 80 | 22 | 1,735 | 391 |
| Egypt | 107 | | 690 | 222 |
| Australia | 29 | | 596 | 128 |
| North Sea | 120 | 2 | 93 | 138 |
| Argentina | 16 | 5 | 365 | 82 |
| **Proved Undeveloped:** | | | | |
| United States | 203 | 61 | 832 | 403 |
| Canada | 71 | 12 | 403 | 150 |
| Egypt | 17 | | 205 | 51 |
| Australia | 35 | | 1,074 | 214 |
| North Sea | 28 | | 20 | 32 |
| Argentina | 3 | 1 | 97 | 20 |
| **TOTAL PROVED** | 1,183 | 258 | 8,464 | 2,852 |

As of December 31, 2012, Apache had total estimated proved reserves of 1,441 MMbbls of crude oil, condensate, and NGLs and 8.5 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 2.9 billion barrels of oil or 17.1 Tcf of natural gas, of which oil represents 41 percent. As of December 31, 2012, the Company s proved developed reserves totaled 1,982 MMboe and estimated PUD reserves totaled 870 MMboe, or approximately 30 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, 2012, 2011, and 2010, 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 as of December 31, 2012 and 2011, 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 870 MMboe as of December 31, 2012, decreased by 128 MMboe from 998 MMboe of PUD reserves estimated at the end of 2011. Driven by the significant decline in North America natural gas prices, a portion of our PUD reserves fell below the threshold for economic development and were removed from our proved reserves balance. The majority of these pricing revisions were associated with dry gas development projects in Canada. During the year, Apache converted 133 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America, we converted 98 MMboe, with the remaining 35 MMboe in our international areas. We acquired 47 MMboe of PUD reserves during the year. We added 158 MMboe of new PUD reserves through extensions and discoveries and had negative revisions of 200 MMboe associated with changes in product prices and revised development plans.

During the year, a total of approximately $3.4 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2011. A portion of our costs incurred each year relate to development projects that will be converted to proved developed reserves in future years. We spent $1.5 billion on PUD reserve development activity in North America and $1.9 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, 2012.

***Preparation of Oil and Gas Reserve Information***

Apache emphasizes that its 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 2012, the properties selected for each country ranged from 77 to 99 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 83 percent of total proved reserves, including 86 percent of proved developed reserves and 74 percent of PUD reserves.

During 2012, 2011, and 2010, Ryder Scott s review covered 88, 81, and 72 percent, respectively, of the Company s worldwide estimated proved reserves value and 83, 70, and 63 percent, respectively, of the Company s total proved reserves volume. 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. Ryder Scott s review of 2010 covered 59 percent of U.S., 42 percent of Canada, 64 percent of Argentina, 99 percent of Australia, 83 percent of Egypt, and 83 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, 2012, we had 5,976 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 2012, we maintained regional exploration and/or production offices in Tulsa, Oklahoma; Houston, Texas; Midland, Texas; Calgary, Alberta; Cairo, Egypt; Perth, Western Australia; Aberdeen, Scotland; and Buenos Aires, Argentina. Apache leases all of its primary office space, with the exception of our Midland office, which we own. 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 specifical 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 the Clean Gulf Associates, and representatives of governmental agencies. In the event of a spill, the 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.

Both Apache and ADW are members of, and Apache has an employee representative on the executive committee of, Clean Gulf Associates (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. Until December 31, 2012, CGA s equipment was maintained by the Marine Spill Response Corporation (MSRC), a national, private, not-for-profit marine spill response organization, which is funded by grants from the Marine Preservation Association. CGA s equipment maintained by MSRC included a high-volume open sea barge oil skimming system, 11 rigid sweeping arms, an oceangoing boom barge with 25,000 feet of offshore containment boom, a fire boom, six fast response vessels, 12 fast response skimming units, multiple shallow water skimming and recovery systems, wildlife cleaning and rehabilitation facilities, and dispersant inventory. In the event of a spill, MSRC stood ready to mobilize all of this equipment to CGA members. MSRC also handled the maintenance and mobilization of CGA non-marine equipment. Effective January 1, 2013, CGA s marine and non-marine equipment is now maintained by the Clean Gulf Associates Service, LLC. In the event of a spill, this 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 2012, Apache incurred charges for CGA of approximately $380,000 based on a per-member fee and annual production.

In the event that CGA resources are already being utilized, other associations 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. OSRL has equipment stockpiles in Bahrain, Singapore, and Southampton that currently include approximately 153 skimmers, booms (of approximately 12,000 meters), two Hercules aircraft for equipment deployment and aerial dispersant spraying, two additional aircraft, dispersant spray systems and dispersant, floating storage tanks, all-terrain vehicles, and various other equipment. 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 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 s equipment currently includes 19 oil spill response barges with storage capacities between 12,000 and 68,000 barrels, 68 shallow water barges, over 290 skimming systems, approximately 50 self-propelled skimming vessels, 7 mobile communication suites with internet and telephone connections, as well as marine and aviation communication capabilities, various small crafts and shallow water vessels, 22,500 feet of fire boom, and 6 dispersant aircraft. 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 a vessel fleet of more than 328 offshore vessels and supply boats worldwide, as well as access to hundreds of tugs and oil barges from its tug and barge clients. The equipment and resources available to the MSRC and the NRC changes from time to time, and current information is generally available on each company s website. In 2012, Apache s Gulf of Mexico Deepwater region incurred charges for NRC of $12,000 based on annual production and charges for MSRC of approximately $735,000 based on annual production and total wells spud in 2012.

ADW has also retained the Helix Well Containment Group (HWCG) in conjunction with its CGA membership. HWCG is a consortium of 24 deepwater operators in the Gulf of Mexico that have worked on expanding capabilities to rapidly respond to subsea well incidents like the Deepwater Horizon incident. In June 2011, HWCG announced that it is now capable of responding to a subsea well containment incident in water depths of up to 10,000 feet. Each HWCG member company has entered into a mutual aid agreement, allowing any member to draw upon the technical expertise and resources of the group in the event of an incident. ADW s 2012 membership dues were approximately $1 million.

In 2011, ADW also became a member of the Marine Well Containment Company (MWCC) to fulfill the government s permit requirements for containment and oil spill response plans in deepwater Gulf of Mexico operations. In March 2012, ADW assigned its interest in MWCC to Apache Well Containment LLC, another wholly owned Apache subsidiary. 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. MWCC is currently developing a billion-dollar expanded containment system, which is expected to be available in 2013. The MWCC owns and maintains an interim containment system, which became available for use in February 2011. The interim containment system includes a subsea capping stack with the ability to shut in oil flow or to flow the oil via flexible pipes and risers to surface vessels. The system also includes subsea dispersant injection equipment, manifolds, and, through mutual aid among members, capture vessels to provide surface processing and storage. The interim system is designed to meet the BSEE requirements. It can operate in water depths up to 8,000 feet and has storage and processing capacity for up to 60,000 b/d and 120 MMcf/d. The capability of the interim containment system continues to grow as components of the expanded system are completed and delivered. The expanded system is designed to operate in 10,000 feet of water and process up to 100,000 b/d and 200 MMcf/d. Membership in MWCC is open to all companies operating in the U.S. Gulf of Mexico. Members and their affiliates have access to the interim containment system, as well as the expanded system once construction is completed. Non-members will also have access to the systems through a service agreement and fee. As of December 31, 2012, Apache s investment in MWCC totals approximately $88 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.

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 political, 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.

**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 key international markets may materially adversely impact our operating results.***

The U.S. and other world economies are slowly recovering from a 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, 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 2012 ranged from a high of $109.77 per barrel to a low of $77.69 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2012 ranged from a high of $3.90 per MMBtu to a low of $1.91 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, 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 hurricanes in the Gulf of Mexico 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 ruptures and spills;
- fires;

formations with abnormal pressures;

equipment malfunctions;

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

surface spillage and surface or ground water contamination from petroleum constituents 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 full 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
- a sudden 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 the Company 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.***

While the credit markets have recovered in the wake of the global financial crises, they remain 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 the event that any of our indentures or other financing agreements in the future restrict our ability to pay dividends in cash on the mandatory convertible preferred stock, we may be unable to pay dividends in cash on the common stock unless we can refinance amounts outstanding under those agreements. 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 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

increase 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 may affect the completion and commencement of production from development projects.***

We are involved in several large development projects the completion of which 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.

***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 was 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 resulting from operations, subject the lessee to liability for pollution damages 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 effect on 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 on operations.

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

Several countries where Apache operates including Australia, Canada, and the United Kingdom either tax or assess some form of greenhouse gas (GHG) related fees on Company 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 the Company s 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. When released, it is anticipated that as a result of possible significant deficit reduction or comprehensive tax reform measures currently under consideration the proposed budget may repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. These provisions include elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; repeal of the manufacturing tax deduction for oil and natural gas companies; and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities in the U.S. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

***Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by 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 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. 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 December 2012 the people of Egypt ratified a new constitution. Under the new constitution, the government must hold elections for the lower house of parliament within 60 days. 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 20 percent of our 2012 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2012, 17 percent of our estimated discounted future net cash flows and 7 percent of our net capitalized oil and gas property was attributable to Egypt.

***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 44 percent of our 2012 production was outside North America, and approximately 31 percent of our estimated proved oil and gas reserves on December 31, 2012 were located outside North America. As a result, a significant portion of our production and resources are subject to the increased political and economic risks and other factors associated with international operations including, but not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation and resource nationalization, forced renegotiation or modification of existing contracts;
- import and export regulations;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- 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. Various 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.

In addition, continued regional conflict in the Middle East could have the following results, among others:

- volatility in global crude prices, which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world s crude oil supply if transportation avenues are disrupted, leading to further commodity price volatility;
- damage to or destruction of our wells, production facilities, receiving terminals, or other operating assets;
- inability of our service equipment providers to deliver items necessary for us to conduct our operations in the Middle East; and
- lack of availability of drilling rigs, oilfield equipment, or services if third-party providers decide to exit the region.

***Our operations are sensitive to currency rate fluctuations.***

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

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

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

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

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

**ITEM 1B. *UNRESOLVED STAFF COMMENTS***

As of December 31, 2012, 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.

## PART II

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

During 2012, 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 2012 and 2011. 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.

| | 2012 | | | | 2011 | | | |
|---|---|---|---|---|---|---|---|---|
| | Price Range | | Dividends Per Share | | Price Range | | Dividends Per Share | |
| | High | Low | Declared | Paid | High | Low | Declared | Paid |
| First Quarter | $ 112.09 | $ 91.48 | $ 0.17 | $ 0.15 | $ 132.50 | $ 110.29 | $ 0.15 | $ 0.15 |
| Second Quarter | 102.13 | 77.93 | 0.17 | 0.17 | 134.13 | 114.94 | 0.15 | 0.15 |
| Third Quarter | 94.87 | 81.55 | 0.17 | 0.17 | 129.26 | 80.05 | 0.15 | 0.15 |
| Fourth Quarter | 89.08 | 74.50 | 0.17 | 0.17 | 105.64 | 73.04 | 0.15 | 0.15 |

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2013 (last trading day of the month), was $83.76 per share. As of January 31, 2013, there were 391,758,883 shares of our common stock outstanding held by approximately 5,300 stockholders of record and approximately 386,000 beneficial owners.

We have paid cash dividends on our common stock for 48 consecutive years through December 31, 2012. When, and if, declared by our Board of Directors, future dividend payments will depend upon our level of earnings, financial requirements, and other relevant factors.

In 1995, under our stockholder rights plan, each of our common stockholders received a dividend of one preferred stock purchase right (a right ) for each 2.310 outstanding shares of common stock (adjusted for subsequent stock dividends and a two-for-one stock split) that the stockholder owned. These rights were originally scheduled to expire on January 31, 2006. Effective as of that date, the rights were reset to one right per share of common stock, and the expiration was extended to January 31, 2016. Unless the rights have been previously redeemed, all shares of Apache common stock are issued with rights, which trade automatically with our shares of common stock. 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 2013 annual meeting of stockholders, which is incorporated herein by reference.

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, 2007, through December 31, 2012. 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.

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|
| Apache Corporation | $ 100.00 | $ 69.77 | $ 97.34 | $ 113.16 | $ 86.43 | $ 75.45 |
| S & P s Composite 500 Stock Index | 100.00 | 63.00 | 79.67 | 91.68 | 93.61 | 108.59 |
| DJ US Expl & Prod Index | 100.00 | 59.88 | 84.17 | 98.26 | 94.14 | 99.62 |

**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, 2012, 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, 2012 numbers in the following table reflect a total of $1.9 billion ($1.4 billion net of tax) in non-cash write-downs of the carrying value of the Company s Canadian proved oil and gas properties as of March 31, 2012, June 30, 2012, and September 30, 2012, as a result of ceiling test limitations. 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. The 2008 numbers reflect a $5.3 billion ($3.6 billion net of tax) non-cash write-down of the carrying value of the Company s U.S., U.K. North Sea, Canadian, and Argentine proved oil and gas properties as of December 31, 2008.

| | As of or for the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| | (In millions, except per share amounts) | | | | |
| **Income Statement Data** | | | | | |
| Total revenues | $ 17,078 | $ 16,888 | $ 12,092 | $ 8,615 | $ 12,390 |
| Income (loss) attributable to common stock | 1,925 | 4,508 | 3,000 | (292) | 706 |
| Net income (loss) per common share: | | | | | |
| Basic | 4.95 | 11.75 | 8.53 | (0.87) | 2.11 |
| Diluted | 4.92 | 11.47 | 8.46 | (0.87) | 2.09 |
| Cash dividends declared per common share | 0.68 | 0.60 | 0.60 | 0.60 | 0.70 |
| **Balance Sheet Data** | | | | | |
| Total assets | $ 60,737 | $ 52,051 | $ 43,425 | $ 28,186 | $ 29,186 |
| Long-term debt | 11,355 | 6,785 | 8,095 | 4,950 | 4,809 |
| Shareholders equity | 31,331 | 28,993 | 24,377 | 15,779 | 16,509 |
| Common shares outstanding | 392 | 384 | 382 | 336 | 335 |

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.

**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 of this Form 10-K, and the Risk Factors information set forth in Part I, Item 1A 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 drilling, acquisitions, or a combination of both, depending on cost levels, availability of acquisition opportunities, and other factors.

Apache s long-term perspective adheres to a portfolio approach to provide diversity in terms of hydrocarbon mix (crude oil and natural gas), geologic risk, geographic risk, and reserve life in order to achieve consistency in results. Continued volatility in the commodity price environment reinforces the importance of our balanced portfolio. Our 2012 results reflected the benefit of our product balance, as combined crude oil and liquids represented 51 percent of our production but provided 81 percent of our $16.9 billion of oil and gas revenues. In addition, approximately 72 percent of our 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 West Texas Intermediate (WTI)-based prices. Our results also reflected our portfolio s geographic balance, with over one-third of our natural gas produced outside of North America. While Apache s 2012 natural gas price realizations in North America fell 24 percent from the 2011 average, outside North America our 2012 natural gas realizations averaged 13 percent higher than the prior year.

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. In addition, we actively seek to identify and pursue ways to control costs and maximize our cash flow from operations. Our overall approach to managing capital allocation has enabled us to consistently deliver strong cash flows, with record production and revenues in 2012.

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and liquidity needs. Apache has historically utilized cash generated from our operations, available borrowing capacity under our global credit facilities, access to both debt and equity capital markets, and proceeds from the occasional sale of nonstrategic assets to meet our financial needs. Access to the equity markets and the interest cost of debt are greatly influenced by Apache s ability to maintain both a strong balance sheet and generate ongoing operating cash flow. In 2012, we issued $5.0 billion of fixed-rate notes in the current low interest rate environment, using the proceeds from the notes to fund the Cordillera acquisition, pay down maturing debt and commercial paper balances, and for general corporate purposes. The Company s debt-to-capitalization ratio as of December 31, 2012 was 28 percent as compared to 20 percent at December 31, 2011. We believe the liquidity and capital resource alternatives available to us, 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.

Throughout the cycles of our industry, our strategic focus on balanced portfolio growth 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***

For the 12-month period ending December 31, 2012, Apache reported record performances in several key metrics. Results for the year include:

Apache reported its fourth consecutive year of production growth, with annual daily production of oil, natural gas, and natural gas liquids averaging a record 779 Mboe/d, up 4 percent compared with 748 Mboe/d in 2011. Production in the fourth-quarter 2012 averaged 800 Mboe/d, an increase of 5 percent from the 759 Mboe/d averaged in the fourth quarter of 2011.

Liquids production for the year averaged a record 396 Mboe/d, an increase of 7 percent from 371 Mboe/d in 2011. Crude oil accounted for 89 percent of liquids production.

Oil and gas production revenues were a record $16.9 billion, up $137 million from the previous record of $16.8 billion set in 2011, reflecting a 4 percent increase in oil production from the prior year, which offset a $416 million reduction in natural gas revenues as realized prices in North America collapsed.

Apache reported $1.9 billion in income attributable to common stock, or $4.92 per diluted common share, down from $4.5 billion, or $11.47 per share, in 2011. Earnings for 2012 reflect the after-tax impact of oil and gas property write-downs totaling $1.4 billion and certain income tax adjustments of $344 million. For additional discussion regarding these write-downs and tax adjustments, please refer Note 1 Summary of Significant Accounting Policies Property and Equipment and Note 7 Income Taxes 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 $3.8 billion, or $9.48 per diluted common share, down from $4.7 billion, or $11.83 per share, in 2011. 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.

***2013 Outlook***

As we head into 2013, we believe our inventory of exploration and development projects offers numerous growth opportunities. Recent drilling successes and acquisitions of acreage positions across our portfolio have built a robust drilling inventory for the Company. With large-scale development projects currently in progress, our global allocation of capital is critical. Given the present price disparity between oil and natural gas, our near-term focus is exploiting the oil-prone and more liquids-rich gas properties in our portfolio. Our plan for 2013 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. Rate of return will drive our decision making while we continue our focus on costs and operational efficiency.

Our initial 2013 capital budget is approximately $10.5 billion. Approximately $6.4 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 2013 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. 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 2013 production between 3 percent and 5 percent from full-year 2012 production levels. We generally do not project production impacts from weather-related shut-ins or for acquisitions or divestitures because they are specific, discrete events where occurrence and timing is unpredictable. We are, however, targeting asset sales of approximately $2.0 billion in 2013, of which $405 million was completed on February 8, 2013 with the closing of our Chevron Canada transaction.

**Operational Developments**

Apache pursues opportunities for growth through exploration, exploitation, and development drilling, supplemented by strategic acquisitions. In 2012, we invested over $10 billion in capital expenditures across all of our regions while also investing approximately $3.5 billion in various acquisitions.

***Exploration, Exploitation, and Development Activities***

Our internally-generated exploration and drilling opportunities, multi-year development projects, and recent acquisitions provide the foundation for our growth. Highlights of our 2012 drilling successes, exploration discoveries, LNG project milestones, and other opportunities for continued growth include:

*International Activities*

*North Sea Drilling, Exploitation, and Exploration* During 2012, we drilled 21 wells, of which 16 were productive. Two of the highest producing wells were the Beryl B72 well, which commenced production in May at a rate of 11.6 Mb/d and 13.1 MMcf/d, and the Beryl B73 well, which was completed in September with an initial rate of 8.2 Mb/d and 5.9 MMcf/d. A 3-D seismic survey of the Beryl field commenced in early August, which when completed in 2013, will further refine our drilling plans for these Mobil North Sea assets acquired in 2011. We also announced during the year that the U.K. Department of Energy & Climate Change awarded the Company 11 new operated licenses and 1 non-operated license, which added approximately 613,000 gross acres to our North Sea portfolio. This award was effective January 2013 and covers areas surrounding our Beryl field plus two key licenses near the Forties field.

*North Sea Satellite Platform Project* In September, the jacket of the Forties Alpha Satellite Platform was installed, with a topside and bridge scheduled to be delivered during the second quarter of 2013. This platform sits adjacent to the main Alpha Platform and will provide an additional 18 drilling slots beginning in the third quarter of 2013 along with power generation, fluid separation, gas lift compression, and oil export pumping.

*Egypt Discoveries* Apache maintained an active drilling and development program throughout 2012, running an average of 25 rigs and drilling 188 development and injection wells. We also drilled 51 exploration wells with a 55 percent success rate. Our exploration program continues to benefit from the acquisition and evaluation of 3-D seismic surveys that enable the Company to high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic reservoirs.

*Argentina Exploration* Apache focused exploration and development activities primarily in the Neuquén basin during 2012, drilling 28 development wells targeting unconventional Gas Plus gas and shallow oil plays. The region s exploration program included drilling two wells in the Vaca Muerta shale formation. Testing and evaluation of these wells continues in preparation for future drilling opportunities.

*Australia Macedon Field Development* First production is projected in 2013 from four completed gas wells in the Macedon gas field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant being built at Ashburton North in Western Australia. Apache has successfully marketed nearly all of its proved reserves in the Macedon field under long-term contracts. We have a 29-percent non-operating working interest in the field and gas plant.

*Australia Coniston Oil Field Development* The Coniston oil field development project, which lies just north of our 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) that services Apache s Van Gogh oil field. To more effectively control the Van Gogh and Coniston field operations, development, and maintenance efforts, this FPSO (the Ningaloo Vision) was purchased from the previous lessor in January 2012.

*Australia Balnaves Oil Development* The Company continues development of its offshore Balnaves field, an oil accumulation located in a separate reservoir within the large gas reservoirs of our Brunello gas field offshore Western Australia. The field is projected to deliver initial gross production of 30 Mb/d in 2014 through a leased FPSO. Apache has a 65-percent working interest in the operated project.

*Australia Wheatstone LNG Project* During 2011, advances were made on the Chevron-operated Wheatstone LNG development project (Wheatstone) in Western Australia, with binding Sales and Purchase Agreements signed by two Asian customers for the delivery of approximately 60 percent of Apache s net LNG offtake. In 2012, further advances were made on the project with the signing of two non-binding Heads of Agreements, which will take the total committed delivery volumes to over 80 percent once the final binding Sales and Purchase Agreements are signed. These binding Sales and Purchase Agreements are expected to be finalized and signed in 2013. 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 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.

*North American Activities*

*Record Drilling Activity in U.S. Onshore Regions* For 2012, our Permian region s active drilling program continued to set new highs for net production, averaging 108 Mboe/d, up 18 percent from the prior year. Over 72 percent of this production was from crude oil and natural gas liquids. The Central region also achieved record production on the strength of an active drilling program and the Cordillera acquisition. The region drilled over 190 wells during the year and increased production 37 percent compared to the prior year. Oil and liquids growth increased 128 percent as the Central team targeted drilling oil and liquids-rich gas plays primarily on our Granite Wash acreage. Both the Permian and Central regions have continued their active drilling programs into 2013.

*United States Horizontal Drilling* Apache continues to evaluate horizontal drilling potential across our acreage positions, in both conventional and unconventional reservoirs. Nearly all of our drilling activity in the Central region is horizontal, while the Permian region continues to develop a large inventory of horizontal opportunities based on 2012 drilling success in the Cline, Atoka, and Wolfcamp shale formations in the Midland basin of Texas. Horizontal redevelopment of historically conventional fields and reservoirs in the Central basin platform in the Permian region have also yielded positive results during 2012. We anticipate a continued shift to more horizontal drilling throughout 2013.

*New Venture Acreage Positions* During 2012, Apache accumulated acreage positions in several prospective basins. Our New Ventures team has built a 500,000 net acre position in the Mississippian Lime play in Kansas and Nebraska and a 300,000 net acre position in the Williston Basin in Montana. We have commenced drilling activity in both of these plays.

*Gulf of Mexico Deepwater Exploration* Apache s strategic presence in the Gulf of Mexico deepwater portfolio was gained through the 2010 Mariner merger and was extended through our participation in the June 2012 federal lease sale, where we were awarded 28 new deepwater leases. At the end of 2012, the Company held approximately 900,000 gross acres across 166 blocks. The region increased its exploration activity for 2012, having drilled or participated in five wells during 2012, as compared to only two wells in the prior year. We plan to drill or participate in drilling seven wells during 2013.

*Kitimat LNG Project* In December 2012, Apache announced an agreement with Chevron Canada Limited (Chevron Canada) to build and operate the Kitimat LNG project and develop shale gas resources at the Liard and Horn River basins in British Columbia. Chevron Canada and Apache Canada will each hold a 50-percent interest in the Kitimat LNG plant, the Pacific Trail Pipeline, and approximately 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant and pipeline and Apache Canada will operate Horn River and Liard. 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. The transaction was completed on February 8, 2013.

***Merger and Acquisitions of Property and Acreage***

During 2012, 2011, and 2010, we completed approximately $17 billion in acquisitions, leaving Apache poised for growth. As we head into 2013, Apache is focused on further developing our inventory of available drilling opportunities. Each of our acquisitions fits well with our long-term strategy of maintaining a balanced portfolio of core assets by adding high-quality properties with a diversity of geologic and geographic risk, product mix, and reserve life. The acquired properties impacted nine of our ten operating regions and are strategically positioned to benefit from our existing infrastructure and operating experience. For detailed information regarding our recent acquisitions, please see Significant Acquisitions and Divestitures in this Item 7 and Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

***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 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 December 2012 the people of Egypt ratified a new constitution. Under the new constitution, the government must hold elections for the lower house of parliament within 60 days. 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. We currently plan to invest $1.1 billion in Egypt in 2013.

Our operations in Egypt contributed 20 percent of our 2012 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2012, 17 percent of our estimated discounted future net cash flows and 7 percent of our net capitalized oil and gas property was attributable to Egypt. For further information regarding our Egypt region, please see Note 13 Business Segment Information and Note 14 Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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 policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $263 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 Egyptian General Petroleum Corporation (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.

A 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.

***Argentina Tax and Royalty Claims***

ENARGAS, an autonomous entity that functions under the Argentina Ministry of Economy, issued administrative orders creating a tariff charge on all fuel gas used by oil and gas producers in field operations effective December 1, 2011. The tariff charge is applicable to the operations of Company affiliates in Argentina and totaled approximately $24 million in 2012. In addition, in late 2010 and early 2011, the Province of Tierra del Fuego notified Company affiliates of its claims for additional royalty on natural gas, crude oil, and liquefied petroleum gas. The Company s affiliates have initiated legal proceedings challenging both ENARGAS tariff charge and the Province s claims for additional royalty. The Province s claims for additional royalty on liquefied petroleum gas exports have been paid under protest by the Company s affiliates. That payment is expected to resolve the claims for additional royalty on liquefied petroleum gas exports.

**Results of Operations**

***Oil and Gas Revenues***

| | For the Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2012 | | | 2011 | | | 2010 | | |
| | $ Value | | % Contribution | $ Value | | % Contribution | $ Value | | % Contribution |
| | ($ in millions) | | | | | | | | |
| Total Oil Revenues: | | | | | | | | | |
| United States | $ | 4,662 | 35% | $ | 4,163 | 33% | $ | 2,683 | 30% |
| Canada | | 492 | 4% | | 485 | 4% | | 388 | 4% |
| North America | | 5,154 | 39% | | 4,648 | 37% | | 3,071 | 34% |
| Egypt | | 4,050 | 31% | | 4,169 | 33% | | 2,875 | 32% |
| Australia | | 1,218 | 9% | | 1,552 | 12% | | 1,296 | 14% |
| North Sea | | 2,517 | 19% | | 2,072 | 16% | | 1,590 | 18% |
| Argentina | | 271 | 2% | | 238 | 2% | | 209 | 2% |
| International | | 8,056 | 61% | | 8,031 | 63% | | 5,970 | 66% |
| Total (1) | $ | 13,210 | 100% | $ | 12,679 | 100% | $ | 9,041 | 100% |
| Total Gas Revenues: | | | | | | | | | |
| United States | $ | 1,169 | 37% | $ | 1,550 | 43% | $ | 1,409 | 49% |
| Canada | | 751 | 23% | | 1,033 | 29% | | 647 | 23% |
| North America | | 1,920 | 60% | | 2,583 | 72% | | 2,056 | 72% |
| Egypt | | 504 | 16% | | 621 | 17% | | 495 | 17% |
| Australia | | 357 | 11% | | 182 | 5% | | 163 | 6% |
| North Sea | | 188 | 6% | | 19 | 0% | | 16 | 0% |
| Argentina | | 224 | 7% | | 204 | 6% | | 132 | 5% |
| International | | 1,273 | 40% | | 1,026 | 28% | | 806 | 28% |
| Total (2) | $ | 3,193 | 100% | $ | 3,609 | 100% | $ | 2,862 | 100% |
| Natural Gas Liquids (NGL) Revenues: | | | | | | | | | |
| United States | $ | 395 | 73% | $ | 391 | 75% | $ | 208 | 74% |
| Canada | | 79 | 14% | | 99 | 19% | | 39 | 14% |
| North America | | 474 | 87% | | 490 | 94% | | 247 | 88% |
| Egypt | | | | | 1 | 0% | | 2 | 1% |
| North Sea | | 46 | 8% | | | | | | |
| Argentina | | 24 | 5% | | 31 | 6% | | 31 | 11% |
| International | | 70 | 13% | | 32 | 6% | | 33 | 12% |
| Total | $ | 544 | 100% | $ | 522 | 100% | $ | 280 | 100% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total Oil and Gas Revenues: | | | | | | | | |
| United States | $ | 6,226 | 37% | $ | 6,104 | 36% | $ | 4,300 | 35% |
| Canada | | 1,322 | 8% | | 1,617 | 10% | | 1,074 | 9% |
| North America | | 7,548 | 45% | | 7,721 | 46% | | 5,374 | 44% |
| Egypt | | 4,554 | 27% | | 4,791 | 29% | | 3,372 | 28% |
| Australia | | 1,575 | 9% | | 1,734 | 10% | | 1,459 | 12% |
| North Sea | | 2,751 | 16% | | 2,091 | 12% | | 1,606 | 13% |
| Argentina | | 519 | 3% | | 473 | 3% | | 372 | 3% |
| International | | 9,399 | 55% | | 9,089 | 54% | | 6,809 | 56% |
| Total | $ | 16,947 | 100% | $ | 16,810 | 100% | $ | 12,183 | 100% |

(1) Financial derivative hedging activities decreased 2012, 2011, and 2010 oil revenues $146 million, $379 million, and $57 million, respectively.

(2) Financial derivative hedging activities increased 2012, 2011, and 2010 natural gas revenues $414 million, $272 million, and $222 million, respectively.

***Production***

| | For the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | Increase (Decrease) | 2011 | Increase (Decrease) | 2010 |
| Oil Volume b/d: | | | | | |
| United States | 134,123 | 12% | 119,415 | 24% | 96,576 |
| Canada | 15,830 | 11% | 14,252 | (2%) | 14,581 |
| North America | 149,953 | 12% | 133,667 | 20% | 111,157 |
| Egypt [3] | 99,756 | (4%) | 103,912 | 5% | 99,122 |
| Australia | 28,884 | (24%) | 38,228 | (17%) | 45,908 |
| North Sea | 63,692 | 17% | 54,541 | (4%) | 56,791 |
| Argentina | 9,741 | 2% | 9,597 | (4%) | 9,956 |
| International | 202,073 | (2%) | 206,278 | (3%) | 211,777 |
| Total [1] | 352,026 | 4% | 339,945 | 5% | 322,934 |
| Natural Gas Volume Mcf/d: | | | | | |
| United States | 854,099 | (1%) | 864,742 | 18% | 730,847 |
| Canada | 600,680 | (5%) | 632,550 | 60% | 396,005 |
| North America | 1,454,779 | (3%) | 1,497,292 | 33% | 1,126,852 |
| Egypt [3] | 353,738 | (3%) | 365,418 | (3%) | 374,858 |
| Australia | 214,013 | 16% | 185,079 | (7%) | 199,729 |
| North Sea | 57,457 | NM | 2,284 | (4%) | 2,391 |
| Argentina | 213,464 | 1% | 212,311 | 15% | 184,830 |
| International | 838,672 | 10% | 765,092 | 0% | 761,808 |
| Total [2] | 2,293,451 | 1% | 2,262,384 | 20% | 1,888,660 |
| Natural Gas Liquids (NGL) Volume b/d: | | | | | |
| United States | 33,527 | 52% | 22,111 | 60% | 13,777 |
| Canada | 6,258 | 5% | 5,958 | 107% | 2,884 |
| North America | 39,785 | 42% | 28,069 | 68% | 16,661 |
| Egypt | | NM | 49 | NM | 82 |
| North Sea | 1,618 | NM | 4 | NM | |
| Argentina | 3,008 | 0% | 3,018 | (5%) | 3,180 |
| International | 4,626 | 51% | 3,071 | (6%) | 3,262 |
| Total | 44,411 | 43% | 31,140 | 56% | 19,923 |
| BOE per day [4] | | | | | |
| United States | 310,000 | 9% | 285,650 | 23% | 232,161 |
| Canada | 122,201 | (3%) | 125,636 | 51% | 83,466 |
| North America | 432,201 | 5% | 411,286 | 30% | 315,627 |

| | | | | | |
|---|---|---|---|---|---|
| Egypt | 158,713 | (4%) | 164,864 | 2% | 161,680 |
| Australia | 64,552 | (7%) | 69,074 | (13%) | 79,196 |
| North Sea | 74,887 | 36% | 54,925 | (4%) | 57,190 |
| Argentina | 48,326 | 1% | 48,000 | 9% | 43,941 |
| International | 346,478 | 3% | 336,863 | (2%) | 342,007 |
| Total | 778,679 | 4% | 748,149 | 14% | 657,634 |

(1) Approximately 13 percent of 2012 worldwide oil production was subject to financial derivative hedges, compared to 29 percent in 2011 and 12 percent in 2010.

(2) Approximately 13 percent of 2012 worldwide natural gas production was subject to financial derivative hedges, compared to 16 percent in 2011 and 23 percent in 2010.

(3) Gross oil production in Egypt for 2012, 2011, and 2010 was 213,112 b/d, 217,207 b/d, and 189,342 b/d, respectively. Gross natural gas production in Egypt for 2012, 2011, and 2010 was 899,972 Mcf/d, 865,485 Mcf/d, and 798,645 Mcf/d, respectively.

(4) 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***

| | For the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | Increase (Decrease) | 2011 | Increase (Decrease) | 2010 |
| Average Oil Price Per barrel | | | | | |
| United States | $ 94.98 | (1%) | $ 95.51 | 25% | $ 76.13 |
| Canada | 84.89 | (9%) | 93.19 | 28% | 72.83 |
| North America | 93.91 | (1%) | 95.27 | 26% | 75.69 |
| Egypt | 110.92 | 1% | 109.92 | 38% | 79.45 |
| Australia | 115.22 | 4% | 111.22 | 44% | 77.32 |
| North Sea | 107.97 | 4% | 104.09 | 36% | 76.66 |
| Argentina | 75.89 | 12% | 68.02 | 18% | 57.47 |
| International | 108.92 | 2% | 106.67 | 38% | 77.21 |
| Total [(1)] | 102.53 | 0% | 102.19 | 33% | 76.69 |
| Average Natural Gas Price Per Mcf: | | | | | |
| United States | $ 3.74 | (24%) | $ 4.91 | (7%) | $ 5.28 |
| Canada | 3.42 | (23%) | 4.47 | 0% | 4.48 |
| North America | 3.61 | (24%) | 4.72 | (6%) | 5.00 |
| Egypt | 3.90 | (16%) | 4.66 | 29% | 3.62 |
| Australia | 4.55 | 69% | 2.69 | 20% | 2.24 |
| North Sea | 8.95 | (60%) | 22.25 | 19% | 18.64 |
| Argentina | 2.87 | 9% | 2.64 | 35% | 1.96 |
| International | 4.15 | 13% | 3.67 | 27% | 2.90 |
| Total [(2)] | 3.80 | (13%) | 4.37 | 5% | 4.15 |
| Average NGL Price Per barrel | | | | | |
| United States | $ 32.19 | (34%) | $ 48.42 | 17% | $ 41.45 |
| Canada | 34.63 | (24%) | 45.72 | 25% | 36.61 |
| North America | 32.57 | (32%) | 47.85 | 18% | 40.62 |
| Egypt | | NM | 66.36 | NM | 69.75 |
| North Sea | 77.11 | 18% | 65.45 | NM | |
| Argentina | 21.55 | (23%) | 27.90 | 3% | 27.08 |
| International | 40.98 | 43% | 28.56 | 1% | 28.15 |
| Total | 33.45 | (27%) | 45.95 | 19% | 38.58 |

(1) Reflects a per-barrel decrease of $1.13, $3.05, and $0.48 in 2012, 2011, and 2010, respectively, from financial derivative hedging activities.

(2) Reflects a per-Mcf increase of $0.49, $0.33, and $0.32 in 2012, 2011, and 2010, 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. Prices we received for crude oil in 2012 were essentially flat compared to 2011, although prices varied significantly throughout the year as political unrest and economic uncertainty continued to impact market volatility.

Continued volatility in the commodity price environment reinforces the importance of our balanced portfolio approach. Crude oil prices realized in 2012 averaged $102.53 per barrel; however International Dated Brent crudes and sweet crude from the Gulf Coast continue to be priced at a significant premium to WTI-based prices. We are realizing these premium prices on approximately 72 percent of our crude oil production. Our Egypt, Australia, and North Sea regions, which comprise 55 percent of our worldwide oil production, receive International Dated Brent pricing with 2012 oil realizations averaging $110.59 per barrel compared with 2011 oil realizations averaging $108.55 per barrel. Our Gulf Coast regions, which comprise 17 percent of our worldwide oil production and receive similar premiums, had price realizations averaging $108.02 per barrel, remaining essentially flat with 2011 realizations averaging $108.26 per barrel.

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 generally move in the same direction. In Argentina, we currently sell our oil in the domestic market. The Argentine government imposes a sliding-scale tax on oil exports, which significantly influences prices domestic buyers are willing to pay. Domestic oil prices are currently indexed to a $42 per barrel base price, subject to quality adjustments and local premiums, and producers realize a gradual increase or decrease as market prices deviate from the base price. In Tierra del Fuego, similar pricing formulas exist; however, Apache retained the value-added tax collected from buyers, effectively increasing realized prices by 21 percent from sales made until May 2012 (when the Federal Government withdrew the benefit). As a result, 2012 oil prices realized from Tierra del Fuego production averaged $71.81 per barrel as compared to our Neuquén basin production, which averaged $77.50 per barrel.

Apache uses financial instruments to manage a portion of its exposure to fluctuations in crude oil prices, particularly in North America. In 2012, 13 percent of our oil production was subject to financial derivative hedges, reducing revenues by $146 million. In 2011, 29 percent of our oil production was subject to financial derivative hedges, reducing revenues by $379 million. For the year-end status of our derivatives, please 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.

*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.

Apache primarily sells natural gas into the North American market, where realized prices decreased 24 percent compared to 2011; however, approximately one-third of our natural gas is produced outside North America, where our average contracted prices rose 13 percent from 2011. Our primary markets include North America, Egypt, Australia, 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.

- 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 $3.90 per Mcf in 2012.

- 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. 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, prices received on recent contracts are substantially higher than historical levels. During 2012, the region averaged $4.55 per Mcf, a 69 percent increase over 2011 pricing.

Natural gas from the North Sea Beryl field is processed through the SAGE gas plant operated by Apache. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The region averaged $8.95 per Mcf in 2012.

Argentina instituted the Gas Plus program in 2008 to encourage 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 2012, the average Gas Plus volume sold by Apache was 73.2 MMcf/d at an average price of $4.89 per Mcf. For 2013, Apache has signed contracts for total gross volumes to be sold under Gas Plus contracts of 80 MMcf/d at $5.01.

Separate from the Gas Plus program, Apache sells volumes under Argentina s government-regulated pricing and into Argentina s unregulated market. The volumes we are required to sell at regulated prices are set by the government and vary based on seasonal factors and industry category. During 2012, we realized an average price of $0.84 per Mcf on government-regulated sales and an average price of $3.52 per Mcf on our unregulated market sales, for a weighted average of $2.03 per Mcf on non-Gas Plus sales.

Apache uses a variety of fixed-price contracts and derivatives to manage our exposure to fluctuations in natural gas prices, primarily in North America. In 2012, 13 percent of our gas production was subject to financial derivative hedges, increasing revenues by $414 million. In 2011, 16 percent of our gas production was subject to financial derivative hedges, increasing revenues by $272 million. For the year-end status of our derivatives, please 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. For more specific information on marketing arrangements by country, please refer to Part I, Items 1 and 2 Business and Properties of this Form 10-K.

*Crude Oil Revenues*

*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 four-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 activity, primarily in the Deadwood, Spraberry, and Wolfcamp plays. The Central region increased 7.4 Mb/d on properties added from the Cordillera acquisition and drilling and recompletion activity across several Granite Wash formations. 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. Egypt s gross oil production decreased 2 percent, while net oil production decreased 4 percent, a product of the terms of our production sharing contracts.

*2011 vs. 2010* During 2011, crude oil revenues totaled $12.7 billion, $3.7 billion higher than the 2010 total of $9.0 billion, driven by a 33-percent increase in average realized prices and a five-percent increase in worldwide production. Average daily production in 2011 was 339.9 Mb/d, with prices averaging $102.19 per barrel. Crude oil represented 75 percent of our 2011 oil and gas production revenues and 45 percent of our equivalent production, compared to 74 and 49 percent, respectively, in the prior year. Higher realized prices contributed $3.0 billion to the increase in full-year revenues, while higher production volumes added another $0.7 billion.

Worldwide oil production increased 17.0 Mb/d, driven by a 22.8 Mb/d increase in the U.S. The Permian region increased 11.6 Mb/d on properties added from the BP acquisitions, the Mariner merger and drilling and recompletion activity, offset by natural decline. The Gulf of Mexico (GOM) onshore and offshore regions added 8.0 Mb/d as production from the Devon acquisition, the Mariner merger and drilling and recompletion activity was partially offset by natural decline. Central region production increased 3.2 Mb/d on an active drilling program in the Granite Wash play. Egypt s gross oil production increased 15 percent from additional capacity at the Kalabsha oil processing facility, a successful drilling and recompletion program, and volumes acquired in the 2010 BP acquisition. Egypt s net production increased only 5 percent, as higher oil prices impact our cost recovery volumes. Australia production decreased 7.7 Mb/d as a result of repairs to the Van Gogh FPSO vessel, natural decline, and tropical cyclones in the first quarter of 2011.

*Natural Gas Revenues*

*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 one-percent increase in production volumes. Worldwide production rose 31.1 MMcf/d, adding $51 million to revenues. Realized prices in 2012 averaged $3.80 per Mcf, a decrease of $0.57 per Mcf, which reduced revenues by $467 million.

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 GOM 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. Egypt s gross production was up 4 percent while net production decreased 3 percent, a product of the terms of our production sharing contracts.

*2011 vs. 2010* Natural gas revenues for 2011 of $3.6 billion were $747 million higher than 2010 on a five-percent increase in realized prices and a 20-percent increase in production volumes. Realized prices in 2011 averaged $4.37 per Mcf, an increase of $0.22 per Mcf, which added $150 million to revenues. Worldwide production rose 374 MMcf/d, adding another $597 million to revenues.

Worldwide gas production rose 20 percent, driven by a 236.5 MMcf/d, or 60 percent, increase in Canada on additional volumes from properties acquired from BP and an active drilling and completion program. U.S. daily production increased 133.9 MMcf/d, or 18 percent, primarily a result of 2010 acquisition activity. GOM onshore and offshore region production rose 73.4 MMcf/d on new drilling activity and properties acquired from Devon and the Mariner merger. Permian region production increased 56.4 MMcf/d on incremental volumes from properties added from the BP acquisition and Mariner merger and on increased drilling activity. Argentina s production increased 27 MMcf/d from drilling and recompletions. Daily gas production in Australia fell 14.7 MMcf/d on downtime from tropical cyclones and customer maintenance activities resulting in lower takes under our existing contractual arrangements. Egypt s gross production increased 8 percent on a successful drilling program, additional gas throughput at the Obaiyed Gas Plant, and production from properties added in the BP acquisition. Net production decreased 3 percent, as higher prices impacted our cost recovery volumes.

***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.

| | For the Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 (In millions) | 2010 | 2012 | 2011 (Per boe) | 2010 |
| Depreciation, depletion and amortization: | | | | | | |
| Oil and gas property and equipment | | | | | | |
| Recurring | $ 4,812 | $ 3,814 | $ 2,861 | $ 16.88 | $ 13.97 | $ 11.92 |
| Additional | 1,926 | 109 | | 6.76 | 0.40 | |
| Other assets | 371 | 281 | 222 | 1.30 | 1.03 | 0.92 |
| Asset retirement obligation accretion | 232 | 154 | 111 | 0.81 | 0.56 | 0.46 |
| Lease operating costs | 2,968 | 2,605 | 2,032 | 10.41 | 9.54 | 8.47 |
| Gathering and transportation costs | 303 | 296 | 178 | 1.08 | 1.08 | 0.73 |
| Taxes other than income | 862 | 899 | 690 | 3.02 | 3.29 | 2.88 |
| General and administrative expense | 531 | 459 | 380 | 1.86 | 1.68 | 1.58 |
| Merger, acquisitions & transition | 31 | 20 | 183 | 0.11 | 0.07 | 0.77 |
| Financing costs, net | 165 | 158 | 229 | 0.58 | 0.58 | 0.95 |
| Total | $ 12,201 | $ 8,795 | $ 6,886 | $ 42.81 | $ 32.20 | $ 28.68 |

*Depreciation, Depletion and Amortization (DD&A)*

The following table details the changes in recurring DD&A of oil and gas properties between December 31, 2010, and December 31, 2012:

| | Recurring DD&A (In millions) |
|---|---|
| 2010 DD&A | $ 2,861 |
| Volume change | 349 |
| DD&A Rate change | 604 |
| 2011 DD&A | $ 3,814 |
| Volume change | 231 |
| DD&A Rate change | 767 |
| 2012 DD&A | $ 4,812 |

*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.

In addition, 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). 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. The Company also recorded $28 million of additional DD&A in 2012 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.

*2011 vs. 2010* Recurring full-cost depletion expense increased $953 million on an absolute dollar basis: $604 million on higher costs and $349 million from additional production. Our full-cost depletion rate increased $2.05 to $13.97 per boe as costs to acquire, find, and develop reserves, which were significantly impacted by higher oil prices, exceeded our historical cost basis. In 2011, additional depletion expense of $60 million was associated with the write-off of the carrying value of our Chilean oil and gas property leases relinquished during 2011, and $49 million was associated with impairments of new venture seismic activity in countries where Apache is pursuing exploration opportunities but has not yet established a presence. Other asset depreciation increased $59 million over 2010 primarily on higher other asset balances from 2010 acquisitions.

*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 labor, boats, helicopters, materials, and supplies. Oil, which contributed nearly half of our 2012 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties, which in 2012 accounted for all of our production in Australia and the North Sea and 83 percent of our production from the U.S. Gulf Coast regions, and in areas with remote plants and facilities. Workovers accelerate production; hence, activity generally increases with higher commodity prices. Foreign exchange rate fluctuations impact the Company s LOE, with a weakening U.S. dollar adding to per-unit costs and a strengthening U.S. dollar lowering per-unit costs in our international regions.

The following table details the LOE rate impact by component:

**For the Year Ended December 31, 2012**

| | Per boe |
|---|---|
| 2011 LOE | $ 9.54 |
| Repairs and maintenance | 0.39 |
| Labor and pumper costs | 0.31 |
| Non-operated property costs | 0.12 |
| Workover costs | 0.06 |
| Other | 0.10 |
| Other decreased production | 0.01 |
| Acquisitions [1] | (0.12) |
| 2012 LOE | $ 10.41 |

**For the Year Ended December 31, 2011**

| | Per boe |
|---|---|
| 2010 LOE | $ 8.47 |
| FX impact | 0.23 |
| Labor and pumper costs | 0.21 |
| Workover costs | 0.18 |
| Chemicals, power, and fuel | 0.13 |
| Transportation | 0.11 |
| Other | 0.12 |
| Other decreased production | 0.11 |
| Acquisitions [1] | (0.02) |
| 2011 LOE | $ 9.54 |

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

*2012 vs. 2011* Our 2012 LOE increased $363 million from 2011, or 14 percent. On a per-unit basis, LOE increased 9 percent due to higher costs on the items listed above.

*2011 vs. 2010* Our 2011 LOE increased $573 million from 2010, or 28 percent. On a per-unit basis, LOE increased 13 percent due to higher costs on the items listed above.

*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, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In millions) | | |
| Canada | $ 163 | $ 166 | $ 75 |
| U.S. | 69 | 64 | 42 |
| Egypt | 39 | 34 | 31 |
| North Sea | 24 | 25 | 25 |
| Argentina | 8 | 7 | 5 |
| Total Gathering and transportation | $ 303 | $ 296 | $ 178 |

*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.

*2011 vs. 2010* Gathering and transportation costs increased $118 million from 2010. Canada s expense increased $91 million from a combination of an increase in gas volumes, higher average rates, and foreign exchange impacts. Average per-unit costs were directly influenced by Apache s increased production in Canada s Horn River basin and properties acquired during 2010, where the associated gathering, processing, and transportation contracts have higher average rates than Apache s legacy properties. The $22 million increase in the U.S. is directly related to increased volumes.

*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 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, Saskatchewan Capital tax, and Saskatchewan Resources surtax. We also pay taxes on invoices and bank transactions in Argentina. The table below presents a comparison of these expenses:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In millions) | |
| U.K. PRT | $ 451 | $ 538 | $ 422 |
| Severance taxes | 220 | 212 | 142 |
| Ad valorem taxes | 104 | 94 | 80 |
| Other | 87 | 55 | 46 |
| Total Taxes other than income | $ 862 | $ 899 | $ 690 |

*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.

*2011 vs. 2010* Taxes other than income were $209 million higher than 2010. U.K. PRT increased $116 million over the comparable 2010 period as a result of an increase in net receipts, primarily driven by higher revenues. Prior-year property acquisitions and higher realized oil and gas prices resulted in a $70 million and $14 million increase to severance and ad valorem tax expense, respectively.

*General and Administrative Expenses*

*2012 vs. 2011* General and administrative (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 on growth-related increases, less $0.08 on increased production.

*2011 vs. 2010* G&A expenses increased $79 million, or 21 percent from 2010. On a per-unit basis, G&A expenses increased 6 percent, or $0.11 per boe: $0.07 per boe on higher insurance costs and $0.04 per boe on nonrecurring expenses.

*Merger, Acquisitions & Transition Costs*

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

In 2011, the Company recognized $20 million in merger, acquisitions, & 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.

In 2010, the Company recognized $183 million in merger, acquisitions, & transition costs related to our BP and Devon acquisitions and the Mariner merger. A summary of these costs follows:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In millions) | | |
| Separation and retention costs | $ 12 | $ 12 | $ 114 |
| Investment banking fees | 7 | | 42 |
| Other costs | 12 | 8 | 27 |
| Total Merger, acquisitions & transition costs | $ 31 | $ 20 | $ 183 |

*Financing Costs, Net*

Financing costs incurred during the period comprised the following:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In millions) | | |
| Interest expense | $ 509 | $ 433 | $ 345 |
| Amortization of deferred loan costs | 7 | 5 | 17 |
| Capitalized interest | (334) | (263) | (120) |
| Interest income | (17) | (17) | (13) |
| Total Financing costs, net | $ 165 | $ 158 | $ 229 |

*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.

*2011 vs. 2010* Net financing costs decreased $71 million from 2010. The decrease is primarily related to a $143 million increase in capitalized interest, the result of additional unproved balances from the BP acquisitions and Mariner merger. This decrease is partially offset by an $88 million increase in interest expense from debt issuances in 2010.

*Provision for Income Taxes*

*2012 vs. 2011* The provision for income taxes totaled $2.9 billion in 2012 compared to $3.5 billion in 2011, driven by lower income before income taxes and an increase in the effective tax rate to 59.0 percent from 43.4 percent in 2011. The 2012 effective rate reflects the tax impact from the $1.9 billion Canadian non-cash write-down, a North Sea decommissioning tax rate adjustment charge, and other tax adjustments. As part of the increase in the corporate income tax rate on North Sea oil and gas profits from 50 percent to 62 percent announced in March 2011, the U.K. government also proposed that the corporation income tax relief attributable to decommissioning expenditures in the North Sea remain at 50 percent. Related legislation was then introduced in Finance Bill 2012 and was enacted on July 17, 2012, upon receiving Royal Assent. As a result of this enacted legislation the Company recorded a non-recurring tax charge of $118 million in the third quarter of 2012. For additional information regarding income taxes, please see Note 7 Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

*2011 vs. 2010* The provision for income taxes totaled $3.5 billion in 2011 compared to $2.2 billion in 2010, driven by a 55 percent increase in income before income taxes and an increase in the effective tax rate to 43.4 percent in 2011 from 41.8 percent in 2010. The largest driver of the increased tax rate was an increase in the U.K. corporate income tax rate on North Sea oil and gas profits from 50 percent to 62 percent. As a result of the enacted legislation, in 2011 the Company recorded a tax charge of $218 million resulting from the remeasurement of our U.K. deferred tax liability as of December 31, 2010. The effective rates for 2011 and 2010 were also impacted by the effect of currency exchange rates on our foreign deferred tax liabilities.

**Significant Acquisitions and Divestitures**

***2012 Activity***

On December 24, 2012, Apache Canada and Chevron Canada entered into an agreement pursuant to which each will become a 50-percent owner of the Kitimat LNG plant, the Pacific Trail Pipeline, and 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant, which will be located on the northern British Columbia coast, and the pipeline; Apache Canada will operate Horn River and Liard. Apache s net proceeds from the transaction were approximately $405 million. The transaction closed on February 8, 2013. Apache originally purchased interest in the Kitimat LNG facility and the related proposed pipeline in the first quarter of 2010.

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. The effective date of the transaction was September 1, 2011. 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. The cash paid at closing was funded with a portion of the proceeds from the Company s April 2012 public note offering. For further discussion of the equity issuance and note offering, please see Note 10 Capital Stock and Note 6 Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K and Liquidity in this Item 7.

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. The transaction was funded with debt. YPHPL is the owner of an ammonia plant on the Burrup Peninsula of Western Australia. Apache has supplied gas to the plant since operations commenced in 2006. Yara Australia Pty Ltd (Yara) owns the remaining 51 percent of YPHPL and operates the plant. In addition, Apache also acquired an interest in a planned technical ammonia nitrate plant to be developed with Yara and Orica Limited. The investment in YPHPL is accounted for under the equity method of accounting, with the balance recorded as a component of Deferred charges and other in Apache s consolidated balance sheet and results of operations recorded as a component of Other under Revenues and Other in the Company s statement of consolidated operations.

***2011 Activity***

On December 30, 2011, Apache completed the acquisition of Exxon Mobil Corporation s U.K. subsidiary, Mobil North Sea Limited. The assets acquired include: operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields; operated interest in the Beryl/Brae gas pipeline and the SAGE gas plant; non-operated interests in the Maclure, Scott, and Telford fields; and Benbecula (west of Shetlands) exploration acreage. This acquisition was funded with $1.25 billion of existing cash on hand.

***2010 Activity***

In November 2010, Apache completed the acquisition of Mariner, an independent exploration and production company, in a stock and cash transaction totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt in connection with the merger. The transaction was accounted for as a business combination, with Mariner s assets and liabilities reflected in Apache s financial statements at fair value. Mariner s oil and gas properties are primarily located in the Gulf of Mexico deepwater and shelf, the Permian Basin, and onshore in the Gulf Coast. The Permian Basin and Gulf of Mexico shelf assets are complementary to Apache s existing holdings and provide an inventory of future potential drilling locations, particularly in the Spraberry and Wolfcamp formation oil plays of the Permian Basin.

In the third and fourth quarters of 2010, Apache completed the acquisition of BP s oil and gas operations, related infrastructure, and acreage in the Permian Basin of west Texas and New Mexico, substantially all of BP s Western Canadian upstream natural gas assets, and BP s interests in four development licenses and one exploration concession (East Badr El Din) in the Western Desert of Egypt. The aggregate purchase price of the BP acquisitions, subsequent to exercise of preferential purchase rights, was $6.4 billion, subject to normal post-closing adjustments. The effective date of these acquisitions was July 1, 2010.

In the second quarter of 2010, Apache completed an acquisition of oil and gas assets on the Gulf of Mexico shelf from Devon for $1.05 billion, subject to normal post-closing adjustments. The acquisition from Devon was effective January 1, 2010, and included 477,000 acres across 150 offshore blocks.

For further information regarding these acquisitions, 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 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. Our business, as with other extractive industries, is a depleting one in which each barrel produced must be replaced or the Company and its reserves, a critical source of future liquidity, will shrink. Cash investments are required to fund activity necessary to offset the inherent declines in production and proven 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.

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.

***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, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In millions) | |
| Sources of Cash and Cash Equivalents: | | | |
| Net cash provided by operating activities | $ 8,504 | $ 9,953 | $ 6,726 |
| Fixed-rate debt borrowings | 4,978 | | 2,470 |
| Commercial paper and bank loan borrowings, net | 549 | | 318 |
| Sale of oil and gas properties | 27 | 422 | |
| Proceeds from issuance of common stock | | | 2,258 |
| Proceeds from issuance of depositary shares | | | 1,227 |
| Other | | 84 | 106 |
| | 14,058 | 10,459 | 13,105 |
| Uses of Cash and Cash Equivalents: | | | |
| Capital expenditures [1] | $ 9,531 | $ 7,078 | $ 4,922 |
| Acquisitions | 2,918 | 1,813 | 8,360 |
| Equity investment in Yara Pilbara Holdings Pty Limited (YPHPL) | 439 | | |
| Commercial paper, credit facility and bank loan repayments, net | | 925 | |
| Project financing repayment | | | 350 |
| Payments on fixed-rate notes | 400 | | 1,023 |
| Dividends | 332 | 306 | 226 |
| Other | 573 | 176 | 138 |
| | 14,193 | 10,298 | 15,019 |
| Increase (decrease) in cash and cash equivalents | $ (135) | $ 161 | $ (1,914) |

[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 in determining 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 2012 totaled $8.5 billion, down $1.4 billion from 2011. The decrease reflects the impact of a change in working capital during the fiscal year, higher operating costs, and higher income tax payments in 2012 as compared to the 2011 period.

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.

*Proceeds from Debt, Common Stock, and Share Issuance*

In April 2012, the Company issued $3.0 billion principal amount of senior unsecured notes. The Company used the proceeds to fund the cash portion of the purchase price paid to acquire Cordillera, repay $400 million of notes that matured on April 15, 2012, and for general corporate purposes.

In December 2012, the Company issued $2.0 billion principal amount of senior unsecured notes to repay commercial paper borrowings and for general corporate purposes.

On July 28, 2010, in conjunction with Apache s $6.4 billion acquisition of properties from BP, the Company issued 26.45 million shares of common stock and 25.3 million depositary shares for approximately $3.5 billion in proceeds.

On August 20, 2010, the Company issued $1.5 billion principal amount of senior unsecured notes to repay borrowings under a bridge facility and the Company s commercial paper program that were used to finance the 2010 BP acquisitions. On December 3, 2010, the Company issued $1 billion principal amount of senior unsecured notes to redeem the outstanding public debt of $1.0 billion assumed upon completion of Apache s acquisition of Mariner in November 2010.

For further discussion of the equity issuance and note offerings, please see Note 10 Capital Stock and Note 6 Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

*Commercial Paper and Lines of Credit*

As of December 31, 2012, Apache had $580 million in commercial paper and money market lines of credit outstanding. For further discussion of our commercial paper program, please see Liquidity in this Item 7 and Note 6 Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

*Sale of Oil and Gas Properties*

During 2012, Apache completed the sale of certain properties in Canada and the U.S. for $27 million. Divestitures comprised several non-strategic assets. In 2011 Apache completed the sale of certain properties in Canada and the U.S. for $422 million.

We are targeting asset sales of approximately $2.0 billion in 2013, of which $405 million was completed on February 8, 2013 with our Chevron Canada transaction.

*Capital Expenditures*

We fund exploration and development 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 or find high-margin reserves at competitive prices. For these reasons, operating cash flow forecasts are revised monthly in response to changing market conditions and production projections. We routinely adjust our capital budget on a quarterly basis in response to changing market conditions and operating cash flow forecasts.

Historically, we have used a combination of operating cash flows, borrowings under lines of credit and our commercial paper program and, from time to time, issues of public debt or common stock to fund significant acquisitions.

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In millions) | |
| Exploration and Development (E&D): | | | |
| United States | $ 5,151 | $ 2,768 | $ 1,623 |
| Canada | 590 | 817 | 860 |
| North America | 5,741 | 3,585 | 2,483 |
| Egypt | 1,074 | 896 | 757 |
| Australia | 873 | 576 | 624 |
| North Sea | 886 | 823 | 617 |
| Argentina | 289 | 346 | 240 |
| Other International | 98 | 61 | 20 |
| International | 3,220 | 2,702 | 2,258 |
| Worldwide Exploration and Development Costs | 8,961 | 6,287 | 4,741 |
| Gathering, Transmission, and Processing Facilities (GTP): | | | |
| United States | 75 | 27 | |
| Canada | 172 | 148 | 159 |
| Egypt | 33 | 111 | 182 |
| Australia | 441 | 345 | 162 |
| Argentina | 16 | 12 | 3 |
| North Sea | 1 | | |
| Total GTP Costs | 738 | 643 | 506 |
| Asset Retirement Costs | 948 | 819 | 459 |
| Capitalized Interest | 334 | 263 | 120 |
| Capital Expenditures, excluding acquisitions | 10,981 | 8,012 | 5,826 |
| Acquisitions, including GTP | 3,543 | 3,189 | 11,557 |
| Asset Retirement Costs Acquired | 84 | 592 | 847 |
| Total Capital Expenditures | $ 14,608 | $ 11,793 | $ 18,230 |

*Exploration and Development* Worldwide E&D expenditures for 2012 totaled $9 billion, or 43 percent above 2011. E&D spending in North America, which totaled 64 percent of worldwide E&D spending, was up 60 percent from the prior year on increased activity in every U.S. region. Expenditures in the U.S. reflect increased drilling activity in the Permian region, particularly in the Deadwood area, and in our Central region where our active horizontal drilling program in the Granite Wash and Cherokee plays continued to expand. U.S.

expenditures also reflect an increase in leasehold acquisition efforts where we have spent over $1 billion to gain new acreage positions in several prospects, including the Mississippian Lime play in Kansas and Nebraska, the Williston Basin play in Montana and multiple offshore blocks in the GOM Deepwater and Shelf regions. E&D spending in Canada decreased 28 percent from the prior year period as our drilling program has been re-focused to oil and liquids-rich gas plays given current North American gas prices.

E&D expenditures outside of North America increased 19 percent over 2011. Australia spending rose $297 million from increased exploration and development drilling, and Egypt was $178 million higher than the prior year on continued drilling activity across all major basins. E&D spending in the North Sea was up $63 million on Beryl field development activity, following the field s acquisition at the end of 2011.

*Gathering, Transmission and Processing Facilities* We invested $738 million in GTP in 2012 compared to $643 million in 2011. The increase is primarily related to Australia, driven by the purchase of the Ningaloo Vision FPSO and higher expenditures for the Wheatstone LNG project.

*Asset Retirement Costs* During 2012, we recorded $603 million of additional future abandonment liabilities and deferred tax liabilities directly attributable to Apache s active exploration and development capital program. An additional $345 million of abandonment costs were recognized for upward revisions to prior-year estimates of timing and costs, particularly in Australia and Canada.

*Acquisitions* We acquired $3.5 billion of oil and gas properties and GTP in 2012 compared to $3.2 billion in 2011. Acquisition capital expenditures occur as attractive opportunities arise and, therefore, vary from year to year. For information regarding our acquisitions and divestitures, please see Significant Acquisitions and Divestitures in this Item 7 and Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

*Equity Investment in YPHPL*

On January 31, 2012, a subsidiary of Apache Energy Limited completed the acquisition of a 49-percent interest in YPHPL (formerly Burrup Holdings Limited) for $439 million, including working capital adjustments. The transaction was funded with debt. The investment in YPHPL is accounted for under the equity method of accounting, with the balance recorded as a component of Deferred charges and other in Apache s consolidated balance sheet and results of operations recorded as a component of Other under Revenues and Other in the Company s statement of consolidated operations.

*Payments on Fixed-Rate Notes*

During the second quarter of 2012 Apache repaid the $400 million in aggregate principal amount of 6.25-percent notes that matured on April 15, 2012.

*Dividends*

The Company has paid cash dividends on its common stock for 48 consecutive years through 2012. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other relevant factors. Common stock dividends paid during 2012 totaled $256 million, compared with $230 million in 2011 and $206 million in 2010. The Company paid dividends on its Series D Preferred Stock totaling $76 million in 2012, compared with $76 million in 2011, and $20 million in 2010.

Based on strong future growth prospects and Apache s financial position, in the first quarter of 2012 the Board of Directors approved a 13-percent increase to $0.17 per share for the regular quarterly cash dividend on the Company s common shares. This increase applied to the dividend on common shares payable on May 22, 2012, to stockholders of record on April 23, 2012, and subsequent dividends paid.

In the first quarter of 2013, the Board of Directors approved a further 18-percent increase to $0.20 per share for the regular quarterly cash dividend on the Company s common shares. This increase applies to the dividend on common shares payable on May 22, 2013, to stockholders of record on April 22, 2013.

***Liquidity***

| | At December 31, 2012 | At December 31, 2011 |
|---|---|---|
| | (In millions, except percentages) | |
| Cash and cash equivalents | $ 160 | $ 295 |
| Total debt | 12,345 | 7,216 |
| Shareholders equity | 31,331 | 28,993 |
| Available committed borrowing capacity | 2,811 | 3,300 |
| Floating-rate debt/total debt | 5% | 0.4% |
| Percent of total debt-to-capitalization | 28% | 20% |

*Cash and Cash Equivalents*

At December 31, 2012, we had $160 million in cash and cash equivalents, of which $155 million of cash was held by foreign subsidiaries, and approximately $5 million was held by 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, 2012, outstanding debt, which consisted of notes, debentures, commercial paper, and uncommitted bank lines, totaled $12.3 billion. Current debt consists of $500 million of 5.25-percent debentures due in April 2013, $400 million in 6.0-percent debentures due in September 2013, and $91 million borrowed under uncommitted money market/overdraft lines of credit in the U.S., Argentina, and Canada. We have $350 million of debt maturing in 2015, $1 million maturing in 2016, $1.4 billion maturing in 2017, and the remaining $9.7 billion maturing intermittently in years 2018 through 2096.

In April 2012 the Company issued $400 million principal amount of senior unsecured 1.75-percent notes maturing April 15, 2017, $1.1 billion principal amount of senior unsecured 3.25-percent notes maturing April 15, 2022, and $1.5 billion principal amount of senior unsecured 4.75-percent notes maturing April 15, 2043. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The Company used the proceeds to fund the cash portion of the purchase price paid to acquire Cordillera, repay the $400 million 6.25-percent notes that matured on April 15, 2012, and for general corporate purposes.

In December 2012 the Company issued $1.2 billion principal amount of senior unsecured 2.625-percent notes maturing January 15, 2023 and $800 million principal amount of senior unsecured 4.25-percent notes maturing January 15, 2044. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The Company used the proceeds to pay down commercial paper and for general corporate purposes.

*Available Credit Facilities*

On June 4, 2012, the Company entered into a new Global Credit Facility consisting of a $1.7 billion revolving syndicated bank credit facility for the U.S., a $300 million revolving syndicated bank credit facility for Australia, and a $300 million revolving syndicated bank credit facility for Canada, which replaced the

Company s existing syndicated bank credit facilities that were scheduled to mature in May 2013. The new facilities are scheduled to mature on June 4, 2017. There were no changes to the Company s $1.0 billion U.S. credit facility that matures on August 12, 2016.

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, 2012, 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, 2012, the Company s debt-to-capitalization ratio was 28 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 $3.0 billion as of December 31, 2012. 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, 2012.

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 24 banks in our bank group. Having a large bank group allows the Company to mitigate the potential impact of any bank s failure to honor its lending commitment.

*Commercial Paper Program*

In June 2012 the Company increased the size of its commercial paper program from $2.95 billion to $3.0 billion, which generally enables Apache to borrow funds for up to 270 days at competitive interest rates. Our 2012 weighted-average interest rate for commercial paper was 0.43 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, 2012, the Company had $489 million in commercial paper outstanding.

*Total Debt-to-Capitalization*

The Company s debt-to-capitalization ratio as of December 31, 2012 was 28 percent as compared to 20 percent at December 31, 2011. The increase in our debt-to-capitalization ratio is directly related to the 2012 notes issued for funding the Cordillera acquisition, to pay down commercial paper balances, and for general corporate purposes. 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.

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.

*Off-Balance Sheet Arrangements*

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

***Contractual Obligations***

The following table summarizes the Company s contractual obligations as of December 31, 2012. 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 | 2013 | 2014-2015 | 2016-2017 | 2018 & Beyond |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| Debt, at face value | Note 6 | $ 12,411 | $ 991 | $ 350 | $ 1,390 | $ 9,680 |
| Interest payments | Note 6 | 11,007 | 533 | 1,035 | 994 | 8,445 |
| Drilling rig commitments [2] | Note 8 | 896 | 602 | 289 | 3 | 2 |
| Purchase obligations [3] | Note 8 | 2,588 | 1,200 | 1,182 | 184 | 22 |
| Firm transportation agreements | Note 8 | 763 | 148 | 264 | 134 | 217 |
| Office and related equipment | Note 8 | 402 | 49 | 91 | 96 | 166 |
| Other operating lease obligations [4] | Note 8 | 754 | 209 | 316 | 205 | 24 |
| Total Contractual Obligations | | $ 28,821 | $ 3,732 | $ 3,527 | $ 3,006 | $ 18,556 |

(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, 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 $104 million for environmental remediation and approximately $12 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 $108 million accrued as of December 31, 2012, 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 a maximum of two storms per year.

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, charterer s liability, 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 $1 billion of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $263 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, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| | **(In millions, except per share data)** | | |
| Income (Loss) Attributable to Common Stock (GAAP) | $ 1,925 | $ 4,508 | $ 3,000 |
| Adjustments: | | | |
| Canada and other oil & gas property write-down, net of tax [(1)] | 1,427 | 60 | |
| Deferred tax adjustments | 226 | (75) | |
| U.K. income tax adjustments | 118 | 218 | |
| Commodity derivative mark-to-market, net of tax [(3)] | 51 | | |
| Merger, acquisitions & transition, net of tax [(2)] | 19 | 13 | 120 |
| Unrealized foreign currency fluctuation impact on deferred tax expense | 1 | (73) | 52 |
| Adjusted Earnings (Non-GAAP) | $ 3,767 | $ 4,651 | $ 3,172 |
| Net Income per Common Share Diluted (GAAP) | $ 4.92 | $ 11.47 | $ 8.46 |
| Adjustments: | | | |
| Canada and other oil & gas property write-down, net of tax [(1)] | 3.53 | 0.15 | |
| Deferred tax adjustments | 0.56 | (0.19) | |
| U.K. income tax adjustments | 0.30 | 0.55 | |
| Commodity derivative mark-to-market, net of tax [(3)] | 0.13 | | |
| Merger, acquisitions & transition, net of tax [(2)] | 0.04 | 0.03 | 0.33 |
| Unrealized foreign currency fluctuation impact on deferred tax expense | | (0.18) | 0.15 |
| Adjusted Earnings Per Share Diluted (Non-GAAP) | $ 9.48 | $ 11.83 | $ 8.94 |

(1) 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) Merger, acquisitions & transition costs recorded in 2012, 2011, and 2010, totaled $31 million, $20 million, and $183 million, respectively, for which a tax benefit of $13 million, $7 million, and $63 million was recognized, respectively. The tax effect was calculated utilizing the statutory rates in effect in each country where costs were incurred.

(3) Commodity derivative mark-to-market losses recorded in 2012 totaled $79 million, for which a tax benefit of $28 million was recognized.

**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 as of December 31, 2012, 2011, and 2010, were 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.

***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 2012, our average crude oil realizations have remained flat at $102.53 per barrel in 2012 compared to $102.19 per barrel in 2011. Our average natural gas price realizations decreased 13 percent in 2012 to $3.80 per Mcf from $4.37 per Mcf in 2011.

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 2012 approximately 13 percent of our natural gas production and approximately 13 percent of our crude oil production was subject to financial derivative hedges, compared with 16 percent and 29 percent, respectively, in 2011.

On December 31, 2012, the Company had open natural gas derivatives in an asset position with a fair value of $48 million. A 10-percent increase in natural gas prices would reduce the fair value by approximately $5 million, while a 10-percent decrease in prices would increase the fair value by approximately $5 million. The Company also had open oil derivatives in a liability position with a fair value of $131 million. A 10-percent increase in oil prices would increase the liability by approximately $438 million, while a 10-percent decrease in prices would move the derivatives to an asset position of $296 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2012. 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 95 percent of the Company s debt. At December 31, 2012, total debt included $580 million of floating-rate debt. As a result, Apache s annual interest costs will fluctuate based on short-term interest rates on approximately 5 percent of our total debt outstanding at December 31, 2012. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $1.4 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 combination of Australian dollar and U.S. dollar fixed-price contracts. Approximately half 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 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 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 as of December 31, 2012, would result in a foreign currency net loss or gain, respectively, of approximately $157 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, 2012, 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, p continue or similar terminology. Although we 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 integration of acquisitions;
- 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, including hydraulic-fracturing regulation and environmental regulation;
- the impact on our operations due to changes in the Egyptian government;
- 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-72 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, 2012, 2011, and 2010, 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 Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2012, 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, 2012, 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.

**Management s Report on Internal Control over Financial Reporting**

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, 2012, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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

None.

# 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 2013 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 2011. 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



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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 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). |
| 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 February 23, 2010, as filed with the Secretary of State of Delaware on February 23, 2010 (incorporated by reference to Exhibit 3.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2009, 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 | Amendment to Restated Certificate of Incorporation of Registrant, dated May 5, 2011, as filed with the Secretary of State of Delaware on May 5, 2011 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed May 11, 2011, SEC File No. 001-4300). |
| 3.4 | Bylaws of Registrant, as amended July 21, 2011 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed July 27, 2011, 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 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). |
| 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 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). |

| 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 | Form of Amended and Restated Credit Agreement, dated as of May 9, 2006, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300). |
| 10.2 | Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of April 5, 2007, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.3 | Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of February 18, 2008, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300). |
| 10.4 | Form of Credit Agreement, dated as of May 12, 2005, among Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, J.P. Morgan Securities Inc. and Banc of America Securities, LLC, as Co-Lead Arrangers and Joint Bookrunners, Bank of America, N.A. and Citibank, N.A., as U.S. Co-Syndication Agents, and Calyon New York Branch and Société Générale, as U.S. Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.01 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300). |
| 10.5 | Form of Credit Agreement, dated as of May 12, 2005, among Apache Canada Ltd, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, RBC Capital Markets and BMO Nesbitt Burns, as Co-Lead Arrangers and Joint Bookrunners, Royal Bank of Canada, as Canadian Administrative Agent, Bank of Montreal and Union Bank of California, N.A., Canada Branch, as Canadian Co-Syndication Agents, and The Toronto-Dominion Bank and BNP Paribas (Canada), as Canadian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.02 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300). |
| 10.6 | Form of Credit Agreement, dated as of May 12, 2005, among Apache Energy Limited, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, Citi securities Limited, as Australian Administrative Agent, Deutsche Bank AG, Sydney Branch, and JPMorgan Chase Bank, as Australian Co-Syndication Agents, and Bank of America, N.A., Sydney Branch, and UBS AG, Australia Branch, as Australian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.03 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.7 | Form of Request for Approval of Extension of Maturity Date and Amendment, dated April 5, 2007, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.6 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300). |
| 10.8 | Form of Request for Approval of Extension of Maturity Date and Amendment, dated February 18, 2008, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300). |
| 10.9 | Credit Agreement, dated August 13, 2010, among Registrant, JPMorgan Chase Bank, N.A., as Administrative Agent, and Citibank, N.A., Bank of America, N.A. and Goldman Sachs Bank USA, as Co-Syndication Agents, J.P. Morgan Securities Inc., Citigroup Global Markets Inc., Banc of America Securities, LLC and Goldman Sachs Bank USA, as Co-Lead Arrangers and Joint Bookrunners, and the lenders party thereto (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed August 16, 2010). |
| 10.10 | 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). |
| 10.11 | 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). |
| 10.12 | 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.13 | 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). |
| 10.14 | 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). |
| 10.15 | 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). |
| 10.16 | 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). |
| 10.17 | 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). |
| 10.18 | Apache Corporation 401(k) Savings Plan, as amended and restated, dated October 28, 2010 (incorporated by reference to Exhibit 10.14 to Registrant s Annual Report on Form 10-K for year ended December 31, 2010, SEC File No. 001-4300). |
| 10.19 | Amendment to Apache Corporation 401(k) Savings Plan, dated December 30, 2010, effective as of November 10, 2010, except as otherwise specified (incorporated by reference to Exhibit 10.15 to Registrant s Annual Report on Form 10-K for year ended December 31, 2010, SEC File No. 001-4300). |
| 10.20 | Amendment to Apache Corporation 401(k) Savings Plan, dated August 31, 2011, effective September 1, 2011 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, SEC File No. 001-4300). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.21 | Amendment to Apache Corporation 401(k) Savings Plan, dated December 19, 2011, effective January 1, 2012, except as otherwise specified (incorporated by reference to Exhibit 10.18 to Registrant s Annual Report on Form 10-K for year ended December 31, 2011, SEC File No. 001-4300). |
| * 10.22 | Amendment to Apache Corporation 401(k) Savings Plan, dated November 8, 2012, effective January 1, 2012. |
| 10.23 | 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). |
| 10.24 | 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). |
| * 10.25 | Amendment to Non-Qualified Retirement/Savings Plan of Apache Corporation, dated November 8, 2012, effective January 1, 2013. |
| 10.26 | 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). |
| * 10.27 | Amendment to Non-Qualified Restorative Retirement Savings Plan of Apache Corporation, dated November 8, 2012, effective January 1, 2013. |
| 10.28 | Apache Corporation 2011 Omnibus Equity Compensation Plan, effective May 5, 2011 (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed May 11, 2011, SEC File No. 001-4300). |
| 10.29 | 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). |
| 10.30 | Apache Corporation 1998 Stock Option Plan, as amended and restated May 5, 2011 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, SEC File No. 001-4300). |
| 10.31 | 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.32 | Apache Corporation 2003 Stock Appreciation Rights Plan, as amended and restated May 4, 2011 (incorporated by reference to Exhibit 10.5 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2011, SEC File No. 001-4300). |
| 10.33 | Apache Corporation 2005 Stock Option Plan, as amended and restated May 5, 2011 (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2011, Commission File No. 001-4300). |
| 10.34 | Apache Corporation 2005 Share Appreciation Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.7 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, Commission File No. 001-4300). |
| 10.35 | Apache Corporation 2008 Share Appreciation Program Specifications, pursuant to Apache Corporation 2007 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300). |
| 10.36 | Apache Corporation Executive Restricted Stock Plan, as amended and restated November 19, 2008 (incorporated by reference to Exhibit 10.37 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300). |
| 10.37 | 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). |
| * 10.38 | Apache Corporation Deferred Delivery Plan, as amended and restated February 5, 2013. |
| * 10.39 | Apache Corporation Non-Employee Directors Compensation Plan, as amended and restated February 6, 2013. |
| * 10.40 | Apache Corporation Outside Directors Retirement Plan, as amended and restated February 6, 2013. |
| 10.41 | 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). |
| 10.42 | 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.43 | Apache Corporation Non-Employee Directors Restricted Stock Units Program Specifications, as amended and restated July 19, 2012, pursuant to Apache Corporation 2011 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, SEC File No. 001-4300). |
| 10.44 | 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). |
| 10.45 | 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). |
| 10.46 | 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). |
| 10.47 | Amended and Restated Conditional Stock Grant Agreement, dated September 15, 2005, effective January 1, 2005, between Registrant and G. Steven Farris (incorporated by reference to Exhibit 10.06 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300). |
| 10.48 | 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). |
| 10.49 | 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). |
| 10.50 | 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). |
| 10.51 | 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.52 | 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). |
| 10.53 | 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). |
| 10.54 | 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). |
| 10.55 | 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). |
| 10.56 | 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). |
| 10.57 | 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). |
| 10.58 | 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). |
| 10.59 | 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). |
| 10.60 | 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). |

| EXHIBIT NO. | DESCRIPTION |
|---|---|
| 10.61 | 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 13, 2012, SEC File No. 001-4300). |
| *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 15, 2011 (incorporated by reference to Exhibit 14.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2011, SEC File No. 001-4300). |
| *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.

## 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 and Chief Executive Officer*

Dated: February 28, 2013

## POWER OF ATTORNEY

The officers and directors of Apache Corporation, whose signatures appear below, hereby constitute and appoint G. Steven Farris, Thomas P. Chambers, P. Anthony Lannie 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<br>G. Steven Farris | Chairman of the Board and Chief Executive Officer (principal executive officer) | February 28, 2013 |
| /s/ THOMAS P. CHAMBERS<br>Thomas P. Chambers | Executive Vice President and Chief Financial Officer (principal financial officer) | February 28, 2013 |
| /s/ REBECCA A. HOYT<br>Rebecca A. Hoyt | Vice President, Chief Accounting Officer and Controller (principal accounting officer) | February 28, 2013 |

| Name | Title | Date |
|---|---|---|
| /s/ RANDOLPH M. FERLIC<br>Randolph M. Ferlic | Director | February 28, 2013 |
| /s/ EUGENE C. FIEDOREK<br>Eugene C. Fiedorek | Director | February 28, 2013 |
| /s/ A.D. FRAZIER, JR.<br>A. D. Frazier, Jr. | Director | February 28, 2013 |
| /s/ PATRICIA ALBJERG GRAHAM<br>Patricia Albjerg Graham | Director | February 28, 2013 |
| /s/ SCOTT D. JOSEY<br>Scott D. Josey | Director | February 28, 2013 |
| /s/ CHANSOO JOUNG<br>Chansoo Joung | Director | February 28, 2013 |
| /s/ JOHN A. KOCUR<br>John A. Kocur | Director | February 28, 2013 |
| /s/ GEORGE D. LAWRENCE<br>George D. Lawrence | Director | February 28, 2013 |
| /s/ WILLIAM C. MONTGOMERY<br>William C. Montgomery | Director | February 28, 2013 |
| /s/ RODMAN D. PATTON<br>Rodman D. Patton | Director | February 28, 2013 |
| /s/ CHARLES J. PITMAN<br>Charles J. Pitman | Director | February 28, 2013 |

**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, 2012. 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.* Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2012.

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 and Chief Executive Officer*

*(principal executive officer)*

/s/ Thomas P. Chambers

*Executive Vice President and Chief Financial Officer*

*(principal financial officer)*

/s/ Rebecca A. Hoyt

*Vice President, Chief Accounting Officer and Controller*

*(principal accounting officer)*

Houston, Texas

February 28, 2013

**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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2013

**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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2012 of Apache Corporation and subsidiaries, and our report dated February 28, 2013, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2013

**APACHE CORPORATION AND SUBSIDIARIES**

**STATEMENT OF CONSOLIDATED OPERATIONS**

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In millions, except per common share data) | | |
| REVENUES AND OTHER: | | | |
| Oil and gas production revenues | $ 16,947 | $ 16,810 | $ 12,183 |
| Other | 131 | 78 | (91) |
| | 17,078 | 16,888 | 12,092 |
| OPERATING EXPENSES: | | | |
| Depreciation, depletion, and amortization: | | | |
| Recurring | 5,183 | 4,095 | 3,083 |
| Additional | 1,926 | 109 | |
| Asset retirement obligation accretion | 232 | 154 | 111 |
| Lease operating expenses | 2,968 | 2,605 | 2,032 |
| Gathering and transportation | 303 | 296 | 178 |
| Taxes other than income | 862 | 899 | 690 |
| General and administrative | 531 | 459 | 380 |
| Merger, acquisitions & transition | 31 | 20 | 183 |
| Financing costs, net | 165 | 158 | 229 |
| | 12,201 | 8,795 | 6,886 |
| INCOME BEFORE INCOME TAXES | 4,877 | 8,093 | 5,206 |
| Current income tax provision | 2,199 | 2,263 | 1,222 |
| Deferred income tax provision | 677 | 1,246 | 952 |
| NET INCOME | 2,001 | 4,584 | 3,032 |
| Preferred stock dividends | 76 | 76 | 32 |
| INCOME ATTRIBUTABLE TO COMMON STOCK | $ 1,925 | $ 4,508 | $ 3,000 |
| NET INCOME PER COMMON SHARE: | | | |
| Basic | $ 4.95 | $ 11.75 | $ 8.53 |
| Diluted | $ 4.92 | $ 11.47 | $ 8.46 |
| WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING: | | | |
| Basic | 389 | 384 | 352 |
| Diluted | 391 | 400 | 359 |
| DIVIDENDS DECLARED PER COMMON SHARE | $ 0.68 | $ 0.60 | $ 0.60 |

The accompanying notes to consolidated financial statements are an integral part of this statement.

**APACHE CORPORATION AND SUBSIDIARIES**

**STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME**

| | For the Year Ended December 31, 2012 | 2011 (In millions) | 2010 |
|---|---|---|---|
| NET INCOME | $ 2,001 | $ 4,584 | $ 3,032 |
| OTHER COMPREHENSIVE INCOME (LOSS): | | | |
| Pension and postretirement benefit plan, net of tax | (2) | (1) | (2) |
| Commodity cash flow hedge activity, net of tax: | | | |
| Reclassification of (gain) loss on settled derivative instruments | (199) | 19 | (106) |
| Change in fair value of derivative instruments | 79 | 115 | 256 |
| Derivative hedge ineffectiveness reclassified into earnings | | (1) | 1 |
| | (122) | 132 | 149 |
| COMPREHENSIVE INCOME | 1,879 | 4,716 | 3,181 |
| Preferred stock dividends | 76 | 76 | 32 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON STOCK | $ 1,803 | $ 4,640 | $ 3,149 |

The accompanying notes to consolidated financial statements are an integral part of this statement.

**APACHE CORPORATION AND SUBSIDIARIES**

**STATEMENT OF CONSOLIDATED CASH FLOWS**

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In millions) | | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income | $ 2,001 | $ 4,584 | $ 3,032 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion, and amortization | 7,109 | 4,204 | 3,083 |
| Asset retirement obligation accretion | 232 | 154 | 111 |
| Provision for deferred income taxes | 677 | 1,246 | 952 |
| Other | 226 | 46 | 190 |
| Changes in operating assets and liabilities: | | | |
| Receivables | 12 | (759) | (496) |
| Inventories | (59) | (37) | 35 |
| Drilling advances | (343) | 26 | (28) |
| Deferred charges and other | 61 | 27 | (141) |
| Accounts payable | (100) | 241 | 214 |
| Accrued expenses | (1,142) | 90 | (309) |
| Deferred credits and noncurrent liabilities | (170) | 131 | 83 |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | 8,504 | 9,953 | 6,726 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Additions to oil and gas property | (8,781) | (6,414) | (4,407) |
| Additions to gas gathering, transmission, and processing facilities | (750) | (664) | (515) |
| Acquisition of Cordillera Energy Partners III, LLC | (2,666) | | |
| Acquisition of Yara Pilbara Holdings Pty Limited | (439) | | |
| Acquisition of Devon properties | | | (1,018) |
| Acquisition of BP properties and facilities | | | (6,429) |
| Mariner Energy, Inc. merger | | | (787) |
| Acquisition of Mobil North Sea Limited | | (1,246) | |
| Acquisitions, other | (252) | (567) | (126) |
| Proceeds from sale of oil and gas properties | 27 | 422 | |
| Other, net | (563) | (176) | (121) |
| NET CASH USED IN INVESTING ACTIVITIES | (13,424) | (8,645) | (13,403) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Commercial paper, credit facility and bank notes, net | 549 | (925) | (32) |
| Fixed rate debt borrowings | 4,978 | | 2,470 |
| Payments on fixed rate debt | (400) | | (1,023) |
| Proceeds from issuance of common stock | | | 2,258 |
| Proceeds from issuance of mandatory convertible preferred stock | | | 1,227 |
| Dividends paid | (332) | (306) | (226) |
| Other | (10) | 84 | 89 |
| NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES | 4,785 | (1,147) | 4,763 |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (135) | 161 | (1,914) |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR | 295 | 134 | 2,048 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | $ 160 | $ 295 | $ 134 |

| | | | |
|---|---|---|---|
| SUPPLEMENTARY CASH FLOW DATA: | | | |
| Interest paid, net of capitalized interest | $ 146 | $ 156 | $ 187 |
| Income taxes paid, net of refunds | 2,590 | 1,686 | 1,170 |

The accompanying notes to consolidated financial statements are an integral part of this statement.

**APACHE CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEET**

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 160 | $ 295 |
| Receivables, net of allowance | 3,086 | 3,079 |
| Inventories | 908 | 655 |
| Drilling advances | 584 | 229 |
| Derivative instruments | 31 | 304 |
| Prepaid assets and other | 193 | 241 |
| | 4,962 | 4,803 |
| PROPERTY AND EQUIPMENT: | | |
| Oil and gas, on the basis of full-cost accounting: | | |
| Proved properties | 78,383 | 67,805 |
| Unproved properties and properties under development, not being amortized | 8,754 | 5,530 |
| Gathering, transmission, and processing facilities | 5,955 | 5,175 |
| Other | 1,055 | 709 |
| | 94,147 | 79,219 |
| Less: Accumulated depreciation, depletion, and amortization | (40,867) | (33,771) |
| | 53,280 | 45,448 |
| OTHER ASSETS: | | |
| Goodwill | 1,289 | 1,114 |
| Deferred charges and other | 1,206 | 686 |
| | $ 60,737 | $ 52,051 |
| **LIABILITIES AND SHAREHOLDERS EQUITY** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 1,092 | $ 1,048 |
| Current debt | 990 | 431 |
| Current asset retirement obligation | 478 | 447 |
| Derivative instruments | 116 | 113 |
| Other current liabilities | 2,860 | 2,924 |
| | 5,536 | 4,963 |
| LONG-TERM DEBT | 11,355 | 6,785 |
| DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES: | | |
| Income taxes | 8,024 | 7,197 |
| Asset retirement obligation | 4,100 | 3,440 |
| Other | 391 | 673 |
| | 12,515 | 11,310 |

| | | |
|---|---|---|
| COMMITMENTS AND CONTINGENCIES (Note 8) | | |
| SHAREHOLDERS EQUITY: | | |
| Preferred stock, no par value, 10,000,000 shares authorized, 6% Cumulative Mandatory Convertible, Series D, $1,000 per share liquidation preference, 1,265,000 shares issued and outstanding | 1,227 | 1,227 |
| Common stock, $0.625 par, 860,000,000 shares authorized, 392,712,245 and 385,249,885 shares issued, respectively | 245 | 241 |
| Paid-in capital | 9,859 | 9,066 |
| Retained earnings | 20,161 | 18,500 |
| Treasury stock, at cost, 1,071,475 and 1,132,242 shares, respectively | (30) | (32) |
| Accumulated other comprehensive loss | (131) | (9) |
| | 31,331 | 28,993 |
| | $ 60,737 | $ 52,051 |

The accompanying notes to consolidated financial statements are an integral part of this statement.

**APACHE CORPORATION AND SUBSIDIARIES**

**STATEMENT OF CONSOLIDATED SHAREHOLDERS EQUITY**

| | Series D Preferred Stock | Common Stock | Paid-In Capital | Retained Earnings | Treasury Stock | Accumulated Other Comprehensive (Loss) | Total Shareholders Equity |
|---|---|---|---|---|---|---|---|
| | | | | (In millions) | | | |
| BALANCE AT DECEMBER 31, 2009 | $ | $ 215 | $ 4,634 | $ 11,437 | $ (217) | $ (290) | $ 15,779 |
| Net income | | | | 3,032 | | | 3,032 |
| Postretirement, net of tax expense of $2 | | | | | | (2) | (2) |
| Commodity hedges, net of tax expense of $62 | | | | | | 151 | 151 |
| Dividends: | | | | | | | |
| Preferred | | | | (32) | | | (32) |
| Common ($0.60 per share) | | | | (214) | | | (214) |
| Mandatory convertible preferred stock issued | 1,227 | | | | | | 1,227 |
| Common stock issuance | | 24 | 3,969 | | 170 | | 4,163 |
| Common stock activity, net | | 1 | 26 | | | | 27 |
| Treasury stock activity, net | | | 1 | | 11 | | 12 |
| Compensation expense | | | 225 | | | | 225 |
| Other | | | 9 | | | | 9 |
| BALANCE AT DECEMBER 31, 2010 | $ 1,227 | $ 240 | $ 8,864 | $ 14,223 | $ (36) | $ (141) | $ 24,377 |
| Net income | | | | 4,584 | | | 4,584 |
| Postretirement, net of tax benefit of $7 | | | | | | (1) | (1) |
| Commodity hedges, net of tax expense of $66 | | | | | | 133 | 133 |
| Dividends: | | | | | | | |
| Preferred | | | | (76) | | | (76) |
| Common ($0.60 per share) | | | | (231) | | | (231) |
| Common stock activity, net | | 1 | 35 | | | | 36 |
| Treasury stock activity, net | | | 2 | | 4 | | 6 |
| Compensation expense | | | 167 | | | | 167 |
| Other | | | (2) | | | | (2) |
| BALANCE AT DECEMBER 31, 2011 | $ 1,227 | $ 241 | $ 9,066 | $ 18,500 | $ (32) | $ (9) | $ 28,993 |
| Net income | | | | 2,001 | | | 2,001 |
| Postretirement, net of income tax benefit of $5 | | | | | | (2) | (2) |
| Commodity hedges, net of tax benefit of $35 | | | | | | (120) | (120) |
| Dividends: | | | | | | | |
| Preferred | | | | (76) | | | (76) |
| Common ($0.68 per share) | | | | (264) | | | (264) |
| Common shares issued | | 3 | 598 | | | | 601 |
| Common stock activity, net | | 1 | (44) | | | | (43) |
| Treasury stock activity, net | | | 1 | | 2 | | 3 |
| Compensation expense | | | 238 | | | | 238 |
| BALANCE AT DECEMBER 31, 2012 | $ 1,227 | $ 245 | $ 9,859 | $ 20,161 | $ (30) | $ (131) | $ 31,331 |

The accompanying notes to consolidated financial statements are an integral part of this statement.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Nature of Operations**

Apache Corporation (Apache or the Company) is an oil and gas exploration and production company with operations in six countries: the United States (U.S.), Canada, Egypt, the United Kingdom (U.K.) North Sea, Australia, and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries.

**1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

Accounting policies used by Apache and its subsidiaries reflect industry practices and conform to accounting principles generally accepted in the U.S. (GAAP). Certain reclassifications have been made to prior periods to conform to current-year presentation. Significant policies are discussed below.

**Principles of Consolidation**

The accompanying consolidated financial statements include the accounts of Apache and its subsidiaries after elimination of intercompany balances and transactions. The Company s interest in oil and gas exploration and production ventures and partnerships are proportionately consolidated. The Company consolidates all other investments in which the Company, either through direct or indirect ownership, has more than a 50-percent voting interest.

**Use of Estimates**

Preparation of financial statements in conformity with GAAP and disclosure of contingent assets and liabilities requires management to make estimates and assumptions that affect reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Apache evaluates its estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of its financial statements and changes in these estimates are recorded when known. Significant estimates made in preparing these financial statements include the fair value determination of acquired assets and liabilities (see Note 2 Acquisitions and Divestitures), the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (see Note 14 Supplemental Oil and Gas Disclosures), the assessment of asset retirement obligations (see Note 5 Asset Retirement Obligation), and the valuation of income taxes (see Note 7 Income Taxes).

**Fair Value Measurements**

Certain assets and liabilities are reported at fair value on a recurring basis in Apache s consolidated balance sheet. Accounting Standards Codification (ASC) 820-10-35 provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models, and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

Fair value measurements are presented in further detail in Note 3 Derivative Instruments, Hedging Activities, Note 6 Debt, and Note 9 Retirement and Deferred Compensation Plans.

**Cash Equivalents**

The Company considers all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. As of December 31, 2012 and 2011, Apache had $160 million and $295 million, respectively, of cash and cash equivalents.

**Accounts Receivable and Allowance for Doubtful Accounts**

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The carrying amount of Apache s accounts receivable approximates fair value because of the short-term nature of the instruments. The Company routinely assesses the collectability of all material trade and other receivables. Many of Apache s receivables are from joint interest owners on properties Apache operates. The Company may have the ability to withhold future revenue disbursements to recover any non-payment of these joint interest billings. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. As of December 31, 2012 and 2011, the Company had an allowance for doubtful accounts of $82 million and $58 million, respectively.

**Inventories**

Inventories consist principally of tubular goods and equipment, stated at weighted-average cost, and oil produced but not sold, stated at the lower of cost or market.

**Property and Equipment**

The carrying value of Apache s property and equipment represents the cost incurred to acquire the property and equipment, including capitalized interest. Interest costs incurred in connection with qualifying capital expenditures are capitalized and amortized in concurrence with the related assets. For business combinations, property and equipment cost is based on the fair values at the acquisition date.

***Oil and Gas Property***

The Company follows the full-cost method of accounting for its oil and gas property. Under this method of accounting, all costs incurred for both successful and unsuccessful exploration and development activities, including salaries, benefits, and other internal costs directly identified with these activities, and oil and gas property acquisitions are capitalized. All costs related to production, general corporate overhead, or similar activities are expensed as incurred. Apache capitalized $404 million, $335 million, and $321 million of internal costs in 2012, 2011, and 2010, respectively.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Proved properties are amortized on a country-by-country basis using the units of production method (UOP). The UOP calculation, in its simplest terms, multiplies the percentage of estimated proved reserves produced each quarter by the cost of those reserves. The amortization base in the UOP calculation includes the sum of proved property, net of accumulated depreciation, depletion and amortization (DD&A), estimated future development costs (future costs to access and develop proved reserves), and asset retirement costs, less related salvage value.

The cost of unproved properties and properties under development are excluded from the amortization calculation until it is determined whether or not proved reserves can be assigned to such properties or until development projects are placed in service. Geological and geophysical costs not associated with specific properties are recorded to proved property immediately. Unproved properties and properties under development are reviewed for impairment at least quarterly. In countries where proved reserves exist, exploratory drilling costs associated with dry holes are transferred to proved properties immediately upon determination that a well is dry and amortized accordingly. In countries where a reserve base has not yet been established, impairments are charged to earnings and are determined through an evaluation considering, among other factors, seismic data, requirements to relinquish acreage, drilling results, remaining time in the commitment period, remaining capital plan and political, economic and market conditions. In 2012, Apache s statement of consolidated operations includes additional DD&A of $28 million related to exiting operations in New Zealand and $15 million of seismic costs incurred in countries where it has no established presence. In 2011, Apache recorded additional DD&A of $60 million related to exiting operations in Chile and $49 million of seismic costs incurred in countries where it has no established presence.

Under the full-cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated ceiling. The ceiling limitation is the estimated after-tax future net cash flows from proved oil and gas reserves, discounted at 10 percent per annum and adjusted for cash flow hedges. Future cash outflows associated with settling accrued asset retirement obligations are excluded from the calculation. 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. See Note 14 Supplemental Oil and Gas Disclosures for a discussion of the calculation of estimated future net cash flows.

Any excess of the net book value of proved oil and gas properties, less related deferred income taxes, over the ceiling is charged to expense and reflected as additional DD&A in the accompanying statement of consolidated operations. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. During 2012, the Company recorded a $1.9 billion ($1.4 billion net of tax) non-cash write-down of the carrying value of the Company s Canadian proved oil and gas properties. Excluding the effects of cash flow hedges in calculating the ceiling limitation, the write-down for the full year would have been higher by $135 million ($101 million net of tax). As of December 31, 2011 and 2010, capitalized costs did not exceed the ceiling limitation, and no write-down was indicated. Cash flow hedges did not materially affect the 2011 or 2010 calculations.

Proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion (greater than 25 percent) of the Company s reserve quantities in a particular country are sold, in which case a gain or loss is recognized in income.

***Gathering, Transmission, and Processing Facilities***

Gathering, transmission, and processing facilities totaled $6.0 billion and $5.2 billion at December 31, 2012 and 2011, respectively. The Company assesses the carrying amount of its gathering, transmission, and processing facilities whenever events or changes in circumstances indicate that their carrying amount may not be

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

recoverable. If the carrying amount of these facilities is less than the sum of the undiscounted cash flows, an impairment loss is recognized for the excess of the carrying value over its fair value. No impairment of gathering, transmission, and processing facilities was recognized during 2012, 2011, or 2010.

Gathering, transmission, and processing facilities, buildings, and equipment are depreciated on a straight-line basis over the estimated useful lives of the assets, which range from three to 25 years. Accumulated depreciation for these assets totaled $1.9 billion and $1.5 billion at December 31, 2012 and 2011, respectively.

***Asset Retirement Costs and Obligations***

The initial estimated asset retirement obligation related to property and equipment is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. If the fair value of the recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of an asset s retirement. Asset retirement costs are depreciated using a systematic and rational method similar to that used for the associated property and equipment. Accretion expense on the liability is recognized over the estimated productive life of the related assets.

**Goodwill**

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. The Company assesses the carrying amount of goodwill by testing for impairment annually and when impairment indicators arise. Goodwill totaled $1.3 billion and $1.1 billion at December 31, 2012 and 2011, respectively. Goodwill of $173 million was booked in the U.S. during 2012 as a result of the acquisition of Cordillera Energy Partners III, LLC, as discussed in Note 2 Acquisitions and Divestitures. As of December 31, 2012 and 2011, $1.0 billion and $843 million was recorded in the U.S. and $84 million and $82 million in the North Sea, respectively. As of December 31, 2012 and 2011, $103 million and $86 million were recorded in Canada and Egypt, respectively. Each country was assessed as a reporting unit, and no impairment of goodwill was recognized during 2012, 2011, or 2010.

**Accounts Payable**

Included in accounts payable at December 31, 2012 and 2011, are liabilities of approximately $255 million and $207 million, respectively, representing the amount by which checks issued but not presented to the Company s banks for collection exceeded balances in applicable bank accounts.

**Commitments and Contingencies**

Accruals for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change.

**Revenue Recognition and Imbalances**

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Apache uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Apache is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties estimated remaining reserves net to Apache will not be sufficient to enable the under-produced owner to recoup its entitled share through production. The Company s recorded liability is generally reflected in other non-current liabilities. No receivables are recorded for those wells where Apache has taken less than its share of production. Gas imbalances are reflected as adjustments to estimates of proved gas reserves and future cash flows in the unaudited supplemental oil and gas disclosures.

Apache markets its own U.S. natural gas production. Since the Company s production fluctuates because of operational issues, it is occasionally necessary to purchase third-party gas to fulfill sales obligations and commitments. Both the costs and sales proceeds of this third-party gas are reported on a net basis in oil and gas production revenues. The costs of third-party gas netted against the related sales proceeds totaled $27 million, $28 million, and $33 million, for 2012, 2011, and 2010, respectively.

The Company s Egyptian operations are conducted pursuant to production sharing contracts under which contractor partners pay all operating and capital costs for exploring and developing the concessions. A percentage of the production, generally up to 40 percent, is available to contractor partners to recover these operating and capital costs over contractually defined terms. Cost recovery is reflected in revenue. The balance of the production is split among the contractor partners and the Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis.

**Derivative Instruments and Hedging Activities**

Apache periodically enters into derivative contracts to manage its exposure to commodity price risk. These derivative contracts, which are generally placed with major financial institutions, may take the form of forward contracts, futures contracts, swaps, or options. The oil and gas reference prices upon which the commodity derivative contracts are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company for its oil and gas production.

Apache accounts for its derivative instruments in accordance with ASC Topic 815, Derivatives and Hedging, which requires that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the balance sheet as either an asset or liability measured at fair value. Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on cash flow hedges to be deferred in other comprehensive income. Realized gains and losses from the Company s oil and gas cash flow hedges, including terminated contracts, are generally recognized in oil and gas production revenues when the forecasted transaction occurs. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current-period income as Other under Revenues and Other in the statement of consolidated operations. If at any time the likelihood of occurrence of a hedged forecasted transaction ceases to be probable, hedge accounting treatment will cease on a prospective basis, and all future changes in the fair value of the derivative will be recognized directly in earnings. Amounts recorded in other comprehensive income prior to the change in the likelihood of occurrence of the forecasted transaction will remain in other comprehensive income until such time as the forecasted transaction impacts earnings. If it becomes probable that the original forecasted production will not occur, then the derivative gain or loss would be reclassified from accumulated other comprehensive income into earnings immediately. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, and any ineffectiveness is immediately reported as Other under Revenues and Other in the statement of consolidated operations.

**General and Administrative Expense**

General and administrative expenses are reported net of recoveries from owners in properties operated by Apache and net of amounts related to lease operating activities or capitalized pursuant to the full-cost method of accounting.

**Income Taxes**

Apache records deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is 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) and changing tax laws.

Earnings from Apache s international operations are permanently reinvested; therefore, the Company does not recognize U.S. deferred taxes on the unremitted earnings of its international subsidiaries. If it becomes apparent that any of the unremitted earnings will be remitted, the Company will then recognize taxes on those earnings.

**Foreign Currency Transaction Gains and Losses**

The U.S. dollar is the functional currency for each of Apache s international operations. The functional currency is determined country-by-country based on relevant facts and circumstances of the cash flows, commodity pricing environment and financing arrangements in each country. Foreign currency transaction gains and losses arise when monetary assets and liabilities denominated in foreign currencies are remeasured to their U.S. dollar equivalent at the exchange rate in effect at the end of each reporting period. Foreign currency gains and losses also arise when revenue and disbursement transactions denominated in a country s local currency are converted to a U.S. dollar equivalent based on the average exchange rates during the reporting period.

The Company accounts for foreign currency gains and losses in accordance with ASC Topic 830, Foreign Currency Matters. Foreign currency transaction gains and losses related to current taxes payable and deferred tax liabilities are recorded as components of the provision for income taxes. In 2012, the Company recorded a net tax expense of $16 million, including a current tax expense of $26 million and deferred tax benefit of $10 million. Included in deferred tax benefit for 2012 is approximately $11 million of tax benefit attributable to realized foreign currency transactions. In 2011, the Company recorded a net tax benefit of $66 million, including a current tax expense of $1 million and deferred tax benefit of $67 million. Included in deferred tax benefit for 2011 is approximately $6 million of tax expense attributable to realized foreign currency transactions. In 2010, the Company recorded net tax expense of $111 million, including a current tax expense of $2 million and deferred tax expense of $109 million. Included in deferred tax expense for 2010 is approximately $57 million of tax expense attributable to realized foreign currency transactions. For further discussion, see Note 7 Income Taxes. All other foreign currency transaction gains and losses are reflected in Other under Revenues and Other in the statement of consolidated operations. The Company s other foreign currency gains and losses netted to a gain in 2012 and 2011 of $24 million and $4 million, respectively, and a loss of $39 million in 2010.

**Insurance Coverage**

The Company recognizes an insurance receivable when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Earnings Per Share**

The Company s basic earnings per share (EPS) amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock was fully vested. The diluted EPS calculation includes additional shares of common stock from the assumed conversion of Apache s convertible preferred stock.

**Stock-Based Compensation**

The Company accounts for stock-based compensation under the fair value recognition provisions of ASC Topic 718, Compensation Stock Compensation. The Company grants various types of stock-based awards including stock options, nonvested restricted stock units, and performance-based awards. Additionally, the Company also grants cash-based stock appreciation rights. These plans and related accounting policies are defined and described more fully in Note 10 Capital Stock. Stock compensation awards granted are valued on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

ASC Topic 718 also requires that benefits of tax deductions in excess of recognized compensation cost be reported as financing cash flows rather than as operating cash flows. The Company classified $4 million, $32 million, and $28 million as financing cash inflows in 2012, 2011, and 2010, respectively.

**Treasury Stock**

The Company follows the weighted-average-cost method of accounting for treasury stock transactions.

**New Pronouncements Issued But Not Yet Adopted**

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, which increases disclosures about offsetting assets and liabilities. New disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared under U.S. GAAP and International Financial Reporting Standards (IFRS) related to the offsetting of financial instruments. The existing U.S. GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. ASU No. 2013-01, released in January 2013, offers clarification on the scope of ASU No. 2011-11 as it applies to derivatives accounted for in accordance with Topic 815. The guidance in ASU No. 2011-11 and No. 2013-01 is effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. The Company does not expect the adoption of this amendment to impact its consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02, which requires preparers to report, in one place, information about reclassifications out of accumulated other comprehensive income (AOCI). The ASU also requires companies to report changes in AOCI balances. The guidance in ASU No. 2013-02 is effective for annual and interim periods beginning after December 15, 2012. The Company does not expect the adoption of this amendment to impact its consolidated financial statements.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## 2. ACQUISITIONS AND DIVESTITURES

**2012 Activity**

***Cordillera Energy Partners III, LLC Acquisition***

On April 30, 2012, Apache completed the acquisition of Cordillera Energy Partners III, LLC (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. The effective date of the transaction was September 1, 2011.

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. The cash paid at closing was funded with a portion of the proceeds from the Company s April 2012 public note offering. For further discussion of this equity issuance, please see Note 10 Capital Stock of this Form 10-K. For further discussion of the note offering, please see Note 6 Debt and Financing Costs of this Form 10-K.

The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the final estimates of the assets acquired and liabilities assumed in the acquisition.

| | (In millions) |
|---|---|
| Current assets | $ 39 |
| Proved properties | 1,040 |
| Unproved properties | 2,299 |
| Gathering, transmission, and processing facilities | 1 |
| Goodwill[1] | 173 |
| Deferred tax asset | 64 |
| Total assets acquired | $ 3,616 |
| Current liabilities | 88 |
| Deferred income tax liabilities | 237 |
| Other long-term obligations | 5 |
| Total liabilities assumed | $ 330 |
| Net assets acquired | $ 3,286 |

(1) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from assets acquired that could not be individually identified and separately recognized. Goodwill is not deductible for tax purposes.

***Yara Pilbara Holdings Pty Limited 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. The transaction was funded with debt. YPHPL is the owner of an ammonia plant on the Burrup Peninsula of Western Australia. Apache has supplied gas to the plant since operations commenced in 2006. Yara Australia Pty Ltd (Yara) owns the remaining 51 percent of YPHPL and operates the plant. In addition, Apache also acquired an interest in a planned technical ammonia nitrate plant to

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

be developed with Yara and Orica Limited. The investment in YPHPL is accounted for under the equity method of accounting, with the balance recorded as a component of Deferred charges and other in Apache s consolidated balance sheet and results of operations recorded as a component of Other under Revenues and Other in the Company s statement of consolidated operations.

**2011 Activity**

***Mobil North Sea Limited Acquisition***

On December 30, 2011, Apache completed the acquisition of Mobil North Sea Limited (Mobil North Sea). The assets acquired include: operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields; operated interest in the Beryl/Brae gas pipeline and the SAGE gas plant; non-operated interests in the Maclure, Scott, and Telford fields; and Benbecula (west of Shetlands) exploration acreage. This acquisition was funded with existing cash on hand.

The transaction was accounted for using the acquisition method of accounting. The following table summarizes the final estimates of the assets acquired and liabilities assumed in the acquisition.

| | (In millions) |
|---|---|
| Current assets | $ 219 |
| Proved properties | 2,341 |
| Unproved properties | 476 |
| Gathering, transmission, and processing facilities | 338 |
| Goodwill[1] | 84 |
| Total assets acquired | $ 3,458 |
| Current liabilities | 148 |
| Asset retirement obligation | 517 |
| Deferred income tax liabilities | 1,546 |
| Other long-term obligations | 1 |
| Total liabilities assumed | $ 2,212 |
| Net assets acquired | $ 1,246 |

(1) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from assets acquired that could not be individually identified and separately recognized. Goodwill is not deductible for tax purposes.

**2010 Activity**

***Gulf of Mexico Shelf Acquisition***

In June 2010, Apache completed an acquisition of oil and gas assets on the Gulf of Mexico shelf from Devon Energy Corporation (Devon) for $1.05 billion, subject to normal post-closing adjustments. The acquisition was effective January 1, 2010, and was funded primarily from existing cash balances.

***BP Acquisitions***

In July 2010, Apache entered into three definitive purchase and sale agreements to acquire properties from subsidiaries of BP plc (collectively referred to as BP ) for aggregate consideration of $7.0 billion. The effective

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

date of the transactions was July 1, 2010. The acquisition of BP s oil and gas operations, related infrastructure and acreage in the Permian Basin of west Texas and New Mexico was completed on August 10, 2010, for an agreed-upon purchase price of $3.1 billion. Apache completed the acquisition of substantially all of BP s western Canadian upstream natural gas assets on October 8, 2010, for $3.25 billion. On November 4, 2010, the Company completed the acquisition of BP s interests in four development licenses and one exploration concession in the Western Desert of Egypt for $650 million. Preferential purchase rights for $658 million of the value of the Permian Basin properties were exercised, and accordingly, the aggregate purchase price for all three transactions was reduced to approximately $6.4 billion, subject to normal post-closing adjustments.

The acquisitions were funded with a combination of common stock, mandatory convertible preferred shares, new term debt, commercial paper and existing cash balances.

***Mariner Energy, Inc. Merger***

In November 2010, Apache acquired Mariner Energy, Inc. (Mariner), an independent exploration and production company, in a stock and cash transaction totaling $2.7 billion and assumed approximately $1.7 billion of Mariner s debt. Mariner s oil and gas properties are primarily located in the Gulf of Mexico deepwater and shelf, the Permian Basin, and onshore in the Gulf Coast region. The transaction was accounted for using the acquisition method of accounting, which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. There were no significant changes to the purchase price subsequent to completion of the acquisition.

***Actual and Pro Forma Impact of Acquisitions (Unaudited)***

Revenues attributable to the Devon acquisition, BP acquisitions, and Mariner merger included in Apache s statement of consolidated operations for the year ended December 31, 2010, were $197 million, $308 million, and $95 million, respectively. Direct expenses attributable to the acquisitions and merger included in the statement of consolidated operations for the same period were $39 million, $78 million, and $26 million, respectively.

The following table presents pro forma information for Apache as if the acquisition of properties from Devon and BP and the Mariner merger occurred on January 1, 2010:

| | For the Year Ended December 31, 2010 (In millions, except per share amounts) |
|---|---|
| Revenues and Other | $ 13,780 |
| Net Income (Loss) | $ 3,364 |
| Preferred Stock Dividends | 76 |
| Income (Loss) Attributable to Common Stock | $ 3,288 |
| Net Income (Loss) per Common Share Basic | $ 8.62 |
| Net Income (Loss) per Common Share Diluted | $ 8.52 |

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the acquisitions and merger and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company s consolidated results of operations actually would

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

have been had the acquisitions and merger been completed on January 1, 2010. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the combined company. The unaudited pro forma consolidated results reflect the following pro forma adjustments:

Adjustment to recognize incremental DD&A expense, using the UOP method, resulting from the purchase of the properties;

Adjustment to recognize adjusted general and administrative expense as a result of the purchase of the properties;

Adjustment to recognize issuance of $1.5 billion principal amount of senior unsecured 5.1-percent notes maturing September 1, 2040, associated deferred financing cost amortization, and interest expense, net of amounts capitalized;

Adjustment to recognize asset retirement obligation accretion on properties acquired;

Adjustment to recognize a pro forma income tax provision;

Adjustment to recognize the issuance of 26.45 million shares of Apache common stock to partially fund the BP acquisitions and 17.3 million shares to partially fund the Mariner merger;

Adjustment to recognize the issuance of 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, issued to fund a portion of the BP acquisitions;

Adjustment to recognize additional dividends associated with the issuance of 6.00-percent Mandatory Convertible Preferred Stock; and

Elimination of transaction costs incurred in 2010 that are directly related to the transactions and do not have a continuing impact on the combined company s operating results.

**Merger, Acquisitions & Transition Expenses**

In 2012, Apache recorded $31 million of expenses reflecting additional costs related to our 2011 acquisition of Mobil North Sea Limited and expenses associated with our 2012 acquisition of Cordillera. In 2011, Apache recorded $20 million of expenses primarily for separation and other costs related to the Mariner merger and the acquisition of Mobil North Sea. In 2010, the Company recorded $183 million of expenses in connection with the acquisition of properties from BP and the Mariner merger: $114 million of separation and other costs; $42 million of investment banking fees; and $27 million of other expenses related to the transactions.

**3. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES**

**Objectives and Strategies**

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its worldwide production. Apache manages the variability in its cash flows by occasionally entering into derivative transactions on a portion of its crude oil and natural gas production. The Company utilizes various types of derivative financial instruments, including swaps and options, to manage fluctuations in cash flows resulting from changes in commodity prices.

**Counterparty Risk**

The use of derivative instruments exposes the Company to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. To reduce the concentration of exposure to any individual counterparty, Apache utilizes a diversified group of investment-grade rated counterparties, primarily financial

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

institutions, for its derivative transactions. As of December 31, 2012, Apache had derivative positions with 15 counterparties. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, Apache may not realize the benefit of some of its derivative instruments resulting from lower commodity prices.

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs a material deterioration in its credit ratings, as defined in the applicable agreement, the other party has the right to demand the posting of collateral, demand a transfer, or terminate the arrangement.

**Derivative Instruments**

As of December 31, 2012, Apache had the following open crude oil derivative positions:

| | Fixed-Price Swaps | | Collars | | |
|---|---|---|---|---|---|
| **Production Period** | **Mbbls[2]** | **Weighted Average Fixed Price[1]** | **Mbbls[2]** | **Weighted Average Floor Price[1]** | **Weighted Average Ceiling Price[1]** |
| 2013 | 40,292 | $ 97.31 | 5,701 | $ 82.84 | $ 111.63 |
| 2014 | 76 | 74.50 | | | |

(1) Crude oil prices represent a weighted average of several contracts entered into on a per-barrel basis. Crude oil contracts are primarily settled against NYMEX WTI Cushing Index and Platts Dated Brent. Approximately 50 percent of 2013 contracts are settled against Dated Brent.

(2) For 2013, fixed-price swaps of 38,320 Mbbls have not been designated as cash flow hedges, and changes in fair value are reflected directly in earnings. All other derivative positions have been designated as cash flow hedges.

As of December 31, 2012, Apache had the following open natural gas derivative positions which have all been designated as cash flow hedges:

| | Fixed-Price Swaps | | Collars | | |
|---|---|---|---|---|---|
| **Production Period** | **MMBtu (in 000 s)** | **Weighted Average Fixed Price[1]** | **MMBtu (in 000 s)** | **Weighted Average Floor Price[1]** | **Weighted Average Ceiling Price[1]** |
| 2013 | 10,095 | $ 6.74 | 6,825 | $ 5.35 | $ 6.67 |
| 2014 | 1,295 | $ 6.72 | | $ | $ |

(1) U.S. natural gas prices represent a weighted average of several contracts entered into on a per-million British thermal units (MMBtu) basis and are settled against NYMEX Henry Hub.

**Fair Value Measurements**

***Commodity Derivative Instruments***

Apache s commodity derivative instruments consist of variable-to-fixed price commodity swaps and options. The fair values of the Company s derivative instruments are not actively quoted in the open market. The Company uses a market approach to estimate the fair values of its derivative instruments, utilizing commodity futures price strips for the underlying commodities provided by a reputable third party. These valuations are Level 2 inputs.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents the Company s derivative assets and liabilities measured at fair value on a recurring basis:

| | Fair Value Measurements Using Quoted Price in Active Markets (Level 1) | Significant Other Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total Fair Value | Netting[1] | Carrying Amount |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| **December 31, 2012** | | | | | | |
| Assets: | | | | | | |
| Commodity Derivative Instruments | $ | $ 48 | $ | $ 48 | $ (15) | $ 33 |
| Liabilities: | | | | | | |
| Commodity Derivative Instruments | | 131 | | 131 | (15) | 116 |
| **December 31, 2011** | | | | | | |
| Assets: | | | | | | |
| Commodity Derivative Instruments | $ | $ 428 | $ | $ 428 | $ (96) | $ 332 |
| Liabilities: | | | | | | |
| Commodity Derivative Instruments | | 250 | | 250 | (96) | 154 |

(1) The derivative fair values are based on analysis of each contract on a gross basis, even where the legal right of offset exists.

The Company accounts for derivative instruments and hedging activity in accordance with ASC Topic 815, Derivatives and Hedging, and all derivative instruments are reflected as either assets or liabilities at fair value in the consolidated balance sheet. These fair values are recorded by netting asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. The fair market value of the Company s derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Current Assets: Derivative instruments | $ 31 | $ 304 |
| Other Assets: Deferred charges and other | 2 | 28 |
| Total Assets | $ 33 | $ 332 |
| Current Liabilities: Derivative instruments | $ 116 | $ 113 |
| Noncurrent Liabilities: Other | | 41 |
| Total Liabilities | $ 116 | $ 154 |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Derivative Activity Recorded in Statement of Consolidated Operations**

The following table summarizes the effect of derivative instruments on the Company s statement of consolidated operations:

| | Gain (Loss) on Derivatives Recognized in Income | For the Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|---|
| | | | (In millions) | |
| Gain (loss) on cash flow hedges reclassified from accumulated other comprehensive loss | Oil and Gas Production Revenues | $ 268 | $ (13) | $ 165 |
| Gain (loss) for ineffectiveness on cash flow hedges | Revenues and Other: Other | $ | $ 2 | $ (2) |
| Loss on derivatives not designated as cash flow hedges | Revenues and Other: Other | $ (79) | $ | $ |

**Derivative Activity in Accumulated Other Comprehensive Income (Loss)**

As of December 31, 2012, a portion of the Company s derivative instruments were designated as cash flow hedges in accordance with ASC Topic 815. A reconciliation of the components of accumulated other comprehensive income (loss) in the statement of consolidated shareholders equity related to Apache s cash flow hedges is presented in the table below:

| | For the Year Ended December 31, 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | Before tax | After tax | Before tax | After tax | Before tax | After tax |
| | | | (In millions) | | | |
| Unrealized gain (loss) on derivatives at beginning of year | $ 145 | $ 114 | $ (54) | $ (19) | $ (267) | $ (170) |
| Realized amounts reclassified into earnings | (268) | (199) | 13 | 19 | (165) | (106) |
| Net change in derivative fair value | 113 | 79 | 188 | 115 | 376 | 256 |
| Ineffectiveness reclassified into earnings | | | (2) | (1) | 2 | 1 |
| Unrealized gain (loss) on derivatives at end of period | $ (10) | $ (6) | $ 145 | $ 114 | $ (54) | $ (19) |

Gains and losses on existing hedges will be realized in future earnings through mid-2014, in the same period as the related sales of natural gas and crude oil production. Included in accumulated other comprehensive loss as of December 31, 2012, is a net loss of approximately $12 million ($7 million after tax) that applies to the next 12 months; however, estimated and actual amounts are likely to vary materially as a result of changes in market conditions.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## 4. OTHER CURRENT LIABILITIES

The following table provides detail of the Company s other current liabilities at December 31, 2012 and 2011:

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Accrued operating expenses | $ 211 | $ 221 |
| Accrued exploration and development | 1,792 | 1,430 |
| Accrued compensation and benefits | 198 | 180 |
| Accrued interest | 160 | 135 |
| Accrued income taxes | 297 | 533 |
| Accrued U.K. Petroleum Revenue Tax | 53 | 284 |
| Other | 149 | 141 |
| Total Other current liabilities | $ 2,860 | $ 2,924 |

## 5. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company s asset retirement obligation (ARO) liability for the years ended December 31, 2012 and 2011:

| | 2012 | 2011 |
|---|---|---|
| | (In millions) | |
| Asset retirement obligation at beginning of year | $ 3,887 | $ 2,872 |
| Liabilities incurred | 592 | 419 |
| Liabilities acquired | 72 | 592 |
| Liabilities settled | (550) | (549) |
| Accretion expense | 232 | 154 |
| Revisions in estimated liabilities | 345 | 399 |
| Asset retirement obligation at end of year | 4,578 | 3,887 |
| Less current portion | (478) | (447) |
| Asset retirement obligation, long-term | $ 4,100 | $ 3,440 |

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. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. 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.

During 2012, the company recorded $592 million in abandonment liabilities resulting from Apache s active exploration and development capital program. An additional $72 million of abandonment obligations were recognized on properties acquired during the year. An additional $345 million of abandonment costs were recognized for upward revisions to prior-year estimates of timing and costs, particularly in Australia and Canada.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Liabilities settled primarily relate to individual properties, platforms, and facilities plugged and abandoned during the period. Apache continues to have an active abandonment program that is focused in the U.S. Gulf of Mexico and Canada. The Company s level of abandonment activity is expected to continue, and $478 million has been recorded as a current liability to reflect our estimated expenditures over the next 12 months.

## 6. DEBT

### Overview

All of the Company s debt is senior unsecured debt and has equal priority with respect to the payment of both principal and interest. The indentures for the notes described below place certain restrictions on the Company, including limits on Apache s ability to incur debt secured by certain liens and its ability to enter into certain sale and leaseback transactions. Upon certain changes in control, all of these debt instruments would be subject to mandatory repurchase, at the option of the holders. None of the indentures for the notes contain prepayment obligations in the event of a decline in credit ratings.

In April 2012 the Company issued $400 million principal amount of senior unsecured 1.75-percent notes maturing April 15, 2017, $1.1 billion principal amount of senior unsecured 3.25-percent notes maturing April 15, 2022, and $1.5 billion principal amount of senior unsecured 4.75-percent notes maturing April 15, 2043. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The Company used the proceeds to fund the cash portion of the purchase price paid to acquire Cordillera, repay the $400 million 6.25-percent notes that matured on April 15, 2012, and for general corporate purposes.

In December 2012 the Company issued $1.2 billion principal amount of senior unsecured 2.625-percent notes maturing January 15, 2023 and $800 million principal amount of senior unsecured 4.25-percent notes maturing January 15, 2044. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The Company used the proceeds to repay commercial paper borrowings and for general corporate purposes.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents the carrying value of the Company s debt at December 31, 2012 and 2011:

| | December 31, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| U.S.: | | |
| Money market lines of credit | $ 13 | $ |
| Commercial paper | 489 | |
| 6.25% notes due 2012(1) | | 400 |
| 5.25% notes due 2013(1) | 500 | 500 |
| 6.0% notes due 2013(1) | 400 | 400 |
| 5.625% notes due 2017(1) | 500 | 500 |
| 1.75% notes due 2017(1) | 400 | |
| 6.9% notes due 2018(1) | 400 | 400 |
| 7.0% notes due 2018 | 150 | 150 |
| 7.625% notes due 2019 | 150 | 150 |
| 3.625% notes due 2021(1) | 500 | 500 |
| 3.25% notes due 2022(1) | 1,100 | |
| 2.625% notes due 2023(1) | 1,200 | |
| 7.7% notes due 2026 | 100 | 100 |
| 7.95% notes due 2026 | 180 | 180 |
| 6.0% notes due 2037(1) | 1,000 | 1,000 |
| 5.1% notes due 2040(1) | 1,500 | 1,500 |
| 5.25% notes due 2042(1) | 500 | 500 |
| 4.75% notes due 2043(1) | 1,500 | |
| 4.25% notes due 2044(1) | 800 | |
| 7.375% debentures due 2047 | 150 | 150 |
| 7.625% debentures due 2096 | 150 | 150 |
| | 11,682 | 6,580 |
| Subsidiary and other obligations: | | |
| Argentina overdraft lines of credit | 69 | 31 |
| Canada lines of credit | 9 | |
| Apache Finance Canada 4.375% notes due 2015(1) | 350 | 350 |
| Notes due in 2016 and 2017 | 1 | 1 |
| Apache Finance Canada 7.75% notes due 2029 | 300 | 300 |
| | 729 | 682 |
| Debt before unamortized discount | 12,411 | 7,262 |
| Unamortized discount | (66) | (46) |
| Total debt | $ 12,345 | $ 7,216 |
| Current maturities | $ (990) | $ (431) |
| Long-term debt | $ 11,355 | $ 6,785 |

(1) These notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The remaining notes and debentures are not redeemable.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Debt maturities as of December 31, 2012, excluding discounts, are as follows:

| | (In millions) |
|---|---|
| 2013 | $ 991 |
| 2014 | |
| 2015 | 350 |
| 2016 | 1 |
| 2017 | 1,389 |
| Thereafter | 9,680 |
| Total Debt, excluding discounts | $ 12,411 |

**Fair Value**

The Company s debt is recorded at the carrying amount on its consolidated balance sheet. The carrying amount of the Company s money market lines of credit and commercial paper approximate fair value because the interest rates are variable and reflective of market rates. Apache uses a market approach to determine the fair value of its fixed-rate debt using estimates provided by an independent investment financial data services firm, which is a Level 2 fair value measurement.

| | December 31, 2012 | | December 31, 2011 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In millions) | | | |
| Money market lines of credit | $ 91 | $ 91 | $ 31 | $ 31 |
| Commercial paper | 489 | 489 | | |
| Notes and debentures | 11,765 | 13,340 | 7,185 | 8,673 |
| Total Debt | $ 12,345 | $ 13,920 | $ 7,216 | $ 8,704 |

**Money Market and Overdraft Lines of Credit**

The Company has certain uncommitted money market and overdraft lines of credit that are used from time to time for working capital purposes. As of December 31, 2012, $91 million was drawn on facilities in the U.S., Argentina, and Canada. As of December 31, 2011, $31 million was drawn on facilities in Argentina.

**Unsecured Committed Bank Credit Facilities**

As of December 31, 2012, 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 for the U.S., a $300 million facility in Australia, and a $300 million facility in Canada. As of December 31, 2012, available borrowing capacity under the Company s credit facilities was $2.8 billion. The committed credit facilities are used to support Apache s commercial paper program.

On June 4, 2012, the Company entered into a new Global Credit Facility consisting of a $1.7 billion revolving syndicated bank credit facility for the U.S., a $300 million revolving syndicated bank credit facility for Australia, and a $300 million revolving syndicated bank credit facility for Canada, which replaced the Company s existing syndicated bank credit facilities that were scheduled to mature in May 2013. The new facilities are scheduled to mature on June 4, 2017. There were no changes to the Company s $1.0 billion U.S. credit facility that matures on August 12, 2016.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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, 2012, 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 U.S. 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, 2012, the Company s debt-to-capitalization ratio was 28 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 $3.0 billion as of December 31, 2012. 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, 2012.

**Commercial Paper Program**

In June 2012, the Company increased the size of its commercial paper program from $2.95 billion to $3.0 billion. This program generally enables Apache to borrow funds for up to 270 days at competitive interest rates. Apache s 2012 weighted-average interest rate for commercial paper was 0.43 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 are available as a 100-percent backstop. The commercial paper program is fully supported by available borrowing capacity under committed credit facilities, which expire in 2016 and 2017. As of December 31, 2012, the Company had $489 million in commercial paper outstanding. There was no outstanding commercial paper at December 31, 2011.

**Subsidiary Notes Apache Finance Canada**

Apache Finance Canada Corporation (Apache Finance Canada) has approximately $300 million of publicly-traded notes due in 2029 and an additional $350 million of publicly traded notes due in 2015 that are fully and unconditionally guaranteed by Apache.

For further discussion of subsidiary debt, please see Note 16 Supplemental Guarantor Information.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Financing Costs, Net**

Financing costs incurred during the periods are composed of the following:

| | For the Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| Interest expense | $ 509 | $ 433 | $ 345 |
| Amortization of deferred loan costs | 7 | 5 | 17 |
| Capitalized interest | (334) | (263) | (120) |
| Interest income | (17) | (17) | (13) |
| Financing costs, net | $ 165 | $ 158 | $ 229 |

The Company has $66 million of debt discounts as of December 31, 2012, which will be charged to interest expense over the life of the related debt issuances. Discount amortization of $3 million, $2 million, and $2 million were recorded as interest expense in 2012, 2011, and 2010, respectively.

As of December 31, 2012 and 2011, the Company had approximately $118 million and $48 million, respectively, of unamortized deferred loan costs associated with its various debt obligations. These costs are included in deferred charges and other in the accompanying consolidated balance sheet and are being charged to financing costs and expensed over the life of the related debt issuances.

**7. INCOME TAXES**

Income before income taxes is composed of the following:

| | For the Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| U.S. | $ 1,605 | $ 2,373 | $ 1,328 |
| Foreign | 3,272 | 5,720 | 3,878 |
| Total | $ 4,877 | $ 8,093 | $ 5,206 |

The total provision for income taxes consists of the following:

| | For the Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| Current taxes: | | | |
| Federal | $ (150) | $ 64 | $ 25 |
| State | | 2 | 4 |
| Foreign | 2,349 | 2,197 | 1,193 |
| | 2,199 | 2,263 | 1,222 |

| | | | |
|---|---|---|---|
| Deferred taxes: | | | |
| Federal | 596 | 656 | 431 |
| State | 10 | 17 | 7 |
| Foreign | 71 | 573 | 514 |
| | 677 | 1,246 | 952 |
| Total | $ 2,876 | $ 3,509 | $ 2,174 |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

A reconciliation of the tax on the Company s income before income taxes and total tax expense is shown below:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In millions) | |
| Income tax expense at U.S. statutory rate | $ 1,707 | $ 2,833 | $ 1,822 |
| State income tax, less federal benefit | 6 | 12 | 6 |
| Taxes related to foreign operations | 773 | 568 | 245 |
| Tax credits | (4) | (15) | (8) |
| Non-deductible merger costs | | | 6 |
| Current and deferred taxes related to currency fluctuations | 16 | (66) | 111 |
| Increase in U.K. tax rate | 118 | 218 | |
| Net change in tax contingencies | (115) | (6) | (2) |
| Increase in valuation allowance | 355 | 8 | 12 |
| All other, net | 20 | (43) | (18) |
| | $ 2,876 | $ 3,509 | $ 2,174 |

The net deferred tax liability consists of the following:

| | December 31, | |
|---|---|---|
| | 2012 | 2011 |
| | (In millions) | |
| Deferred tax assets: | | |
| Deferred income | $ (33) | $ (89) |
| Federal and state net operating loss carryforwards | (932) | (236) |
| Foreign net operating loss carryforwards | (61) | (55) |
| Tax credits | (78) | (66) |
| Accrued expenses and liabilities | (2) | (90) |
| Total deferred tax assets | (1,106) | (536) |
| Valuation allowance | 419 | 60 |
| Net deferred tax assets | (687) | (476) |
| Deferred tax liabilities: | | |
| Other | 23 | 21 |
| Depreciation, depletion and amortization | 8,536 | 7,443 |
| Total deferred tax liabilities | 8,559 | 7,464 |
| Net deferred income tax liability | $ 7,872 | $ 6,988 |

The Company has recorded a valuation allowance against the net deferred tax asset in Canada. The deferred tax position in Canada changed from a net deferred tax liability as of December 31, 2011 to a net deferred tax asset as of December 31, 2012 on $1.9 billion in non-cash ceiling test write-downs. The Company has assessed the realizability of the net deferred tax asset in Canada and has concluded that it is more likely than not that the net deferred tax asset in Canada will not be realized based on current economic conditions.

The Company has not recorded U.S. deferred income taxes on the undistributed earnings of its foreign subsidiaries, as management intends to permanently reinvest such earnings. As of December 31, 2012, the

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

undistributed earnings of the foreign subsidiaries amounted to approximately $15.9 billion. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings after consideration of available foreign tax credits. Presently, limited foreign tax credits are available to reduce the U.S. taxes on such amounts if repatriated.

On December 31, 2012, the Company had net operating losses as follows:

| | December 31, 2012 | |
|---|---|---|
| | Amount (In millions) | Expiration |
| Net operating losses: | | |
| U.S. Federal | $ 2,393 | 2027 |
| U.S. State | 1,648 | Various |
| Canada | 6 | 2014 |
| Australia | 94 | Indefinite |
| Argentina | 55 | 2013 |

The Company has a federal net operating loss carryforward of $2.4 billion. Included in the federal net operating loss carryforward is $543 million of federal net operating losses related to the merger with Mariner and $183 million of federal net operating losses related to the Cordillera acquisition. The Mariner and Cordillera net operating loss carryforwards are subject to annual limitations under Section 382 of the Internal Revenue Code. The Company also had $170 million of capital loss carryforwards in Canada, which have an indefinite carryover period.

The tax benefits of carryforwards are recorded as assets to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforwards is determined to not meet the more likely than not standard, a valuation allowance is provided to reduce the tax benefits from such assets. As the Company does not believe the utilization of certain state net operating losses, Argentinian net operating losses, and Canadian capital losses to be more likely than not, a valuation allowance was provided to reduce the tax benefit from these deferred tax assets.

Apache accounts for income taxes in accordance with ASC Topic 740, Income Taxes, which prescribes a minimum recognition threshold a tax position must meet before being recognized in the financial statements. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| Balance at beginning of year | $ 97 | $ 110 | $ 123 |
| Additions based on tax positions related to the current year | | 13 | (1) |
| Reductions for tax positions of prior years | (29) | (4) | (12) |
| Settlements | (65) | (22) | |
| Balance at end of year | $ 3 | $ 97 | $ 110 |

The Company records interest and penalties related to unrecognized tax benefits as a component of income tax expense. Each quarter the Company assesses the amounts provided for and, as a result, may increase (expense) or reduce (benefit) the amount of interest and penalties. During the years ended December 31, 2012,

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

2011, and 2010 the Company recorded tax expense of $5 million, $6 million, and $12 million, respectively, for interest and penalties. As of December 31, 2012 and 2011, the Company had approximately $6 million and $42 million, respectively, accrued for payment of interest and penalties.

The Company is under IRS audit for 2009 and 2010 and under audit in various states as well as in most of the Company s foreign jurisdictions as part of its normal course of business. In 2012, the Company reached an agreement with IRS Administrative Appeals office regarding the audits of tax years 2004 through 2008. As a result of this agreement, the Company has reduced the unrecognized tax benefit by $65 million. The resolution of unagreed tax issues in the Company s open tax years cannot be predicted with absolute certainty, and differences between what has been recorded and the eventual outcomes may occur. The Company believes that it has adequately provided for income taxes and any related interest and penalties for all open tax years.

Apache and its subsidiaries are subject to U.S. federal income tax as well as income tax in various states and foreign jurisdictions. The Company s uncertain tax positions are related to tax years that may be subject to examination by the relevant taxing authority. Apache s earliest open tax years in its key jurisdictions are as follows:

| **Jurisdiction** | |
|---|---|
| U.S. | 2004 |
| Canada | 2008 |
| Egypt | 1998 |
| Australia | 2008 |
| U.K. | 2011 |
| Argentina | 2005 |

**8. COMMITMENTS AND CONTINGENCIES**

**Legal Matters**

Apache is party to various legal actions arising in the ordinary course of business, including litigation and governmental and regulatory controls. The Company has an accrued liability of approximately $12 million for all legal contingencies that are deemed to be probable of occurring and can be reasonably estimated. Apache s estimates are based on information known about the matters and its experience in contesting, litigating, and settling similar matters. Although actual amounts could differ from management s estimate, none of the actions are believed by management to involve future amounts that would be material to Apache s financial position, results of operations, or liquidity after consideration of recorded accruals. For material matters that Apache believes an unfavorable outcome is reasonably possible, the Company has disclosed the nature of the matter and a range of potential exposure, unless an estimate cannot be made at this time. It is management s opinion that the loss for any other litigation matters and claims that are reasonably possible to occur will not have a material adverse effect on the Company s financial position, results of operations, or liquidity.

***Argentine Environmental Claims***

In connection with the acquisition from Pioneer Natural Resources (Pioneer) in 2006, the Company acquired a subsidiary of Pioneer in Argentina (PNRA) that is involved in various administrative proceedings with environmental authorities in the Neuquén Province relating to permits for and discharges from operations in that province. In addition, PNRA was named in a lawsuit initiated against oil companies operating in the Neuquén basin entitled *Asociación de Superficiarios de la Patagonia v YPF S.A., et. al.*, originally filed on August 21, 2003, in the Argentine National Supreme Court of Justice. The plaintiffs, a private group of landowners known

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

as ASSUPA, have also named the national government and several provinces as third parties. The lawsuit alleges injury to the environment generally by the oil and gas industry. The plaintiffs principally seek from all defendants, jointly, (i) the remediation of contaminated sites, of the superficial and underground waters, and of soil that allegedly was degraded as a result of deforestation, (ii) if the remediation is not possible, payment of an indemnification for the material and moral damages claimed from defendants operating in the Neuquén basin, of which PNRA is a small portion, (iii) adoption of all the necessary measures to prevent future environmental damages, and (iv) the creation of a private restoration fund to provide coverage for remediation of potential future environmental damages. Much of the alleged damage relates to operations by the Argentine state oil company, which conducted oil and gas operations throughout Argentina prior to its privatization, which began in 1990. ASSUPA has recently asserted similar lawsuits and claims against numerous oil and gas producers relating to other geographic areas of Argentina, including claims against a Company subsidiary relating to the Austral basin. While the plaintiffs will seek to make all oil and gas companies jointly liable for each other s actions in each of these lawsuits, Company subsidiaries will defend on an individual basis and attempt to require the plaintiffs to delineate damages by company. Company subsidiaries intend to defend each case vigorously. It is not certain exactly what the courts will do in these matters as the lawsuit relating to the Neuquén basin is the first of its kind. While it is possible Company subsidiaries may incur liabilities related to the environmental claims, no reasonable prediction can be made as the Company subsidiaries exposure related to these lawsuits is not currently determinable.

***U.S. Royalty Litigation***

In *Foster v. Apache Corporation*, Civil Action No. CIV-10-0573-HE, in the United States District Court for the Western District of Oklahoma, on August 20, 2012, the United States District Court for the Western District of Oklahoma denied plaintiff s motion for class certification. The plaintiff filed a motion for reconsideration, which was denied, and has petitioned the United States Court of Appeals for the Tenth Circuit to accept an appeal of the District Court s ruling denying class certification. Plaintiffs in the *Foster* case have asserted that they may seek damages of approximately $100 million. No facts have been introduced that would support that amount or any lesser amount. No specific dollar amount has been claimed. Apache intends to vigorously defend against these claims.

In *Joyce Holder Trust v. Apache Corporation*, Civil Action No. 4:11-cv-03872, in the United States District Court for the Southern District of Texas, Houston Division, following a class certification hearing in the United States District Court for the Southern District of Texas, the parties resolved the matter with no material impact on the Company s financial position, results of operations, or liquidity, and with the settlement providing for denial of class certification and dismissal of the case.

***Louisiana Restoration***

Numerous surface owners have filed claims or sent demand letters to various oil and gas companies, including Apache, claiming that, under either expressed or implied lease terms or Louisiana law, they are liable for damage measured by the cost of restoration of leased premises to their original condition as well as damages from contamination and cleanup, regardless of the value of the underlying property. Because the Company has continuing operations in Louisiana, from time-to-time restoration lawsuits and claims are resolved by the Company for amounts that are not material to the Company while new lawsuits and claims are asserted against the Company. With respect to each of the pending lawsuits and claims, the amount claimed is not currently determinable or is not material, except that in a lawsuit captioned *Ardoin Limited Partnership et al. v. Meridian Resources & Exploration et al.*, Case No.10-18692, in the District Court of Cameron Parish, Louisiana, the plaintiffs expert opined that the cost to restore plaintiffs property would be approximately $61 million. Prior to

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

trial the court granted Apache s motions to dismiss the plaintiffs claims against Apache. Plaintiffs then settled with the other defendant in the case, BP America, Inc. (BP). BP has demanded that Apache indemnify it for the amount of its settlement with plaintiffs, which is not material to Apache. Apache has rejected BP s indemnity claim and, further, Apache has demanded that Wagner Oil Company (which purchased Apache s interest in the subject property) indemnify Apache from and against BP s claim.

In addition to the matters discussed above, in a lawsuit filed on May 4, 2010, against Phoenix Exploration Company LP (Phoenix) captioned *Belle Isle, L.L.C. v. Anadarko Petroleum Corporation et al.*, Docket No. 121742, in the District Court of St. Mary Parish, Louisiana, plaintiff alleges that over three thousand acres of land has been contaminated by oil and gas operations. On August 31, 2011, subsidiaries of Apache acquired 75 percent of the general partner interests and 75 percent of the Class A and Class B limited partner interests in Phoenix. Plaintiff s experts estimated the cost of remediation to be approximately $87 million, and plaintiffs claimed additional damages for canal restoration, among other things, all of which is disputed by the Company s subsidiary. The parties have resolved the matter with no material impact on the Company s financial position, results of operations, or liquidity, and with the settlement providing for certain limited remediation activities on the property.

The overall exposure related to these lawsuits and claims is not currently determinable. While an adverse judgment against Apache is possible, Apache intends to actively defend the cases.

***Hurricane-Related Litigation***

On May 27, 2011, a lawsuit captioned *Comer et al. v. Murphy Oil USA, Inc. et al.*, Case No. 1:11-cv-220 HS0-JMR, in the United States District Court for the Southern District of Mississippi, was filed in which certain named residents of Mississippi, as plaintiffs, allege that the oil, coal, and chemical industries are responsible for global warming, which they claim caused or increased the effect of Hurricane Katrina, allegedly resulting among other things in economic losses and increased insurance premiums. Plaintiffs seek class certification, damages for losses sustained, a declaration that state law tort claims are not pre-empted by federal law, and punitive and exemplary damages. Apache is one of numerous defendants. The District Court has granted defendants motion to dismiss plaintiffs claims, and plaintiffs have appealed the decision to the United States Court of Appeals for the Fifth Circuit. The overall exposure related to this lawsuit is not currently determinable. While an adverse judgment against Apache is possible, Apache intends to vigorously defend the case. A similar action filed by Comer *et al.* was previously dismissed in 2011.

***Australia Gas Pipeline Force Majeure***

In June 2008, Company subsidiaries reported a pipeline explosion that interrupted deliveries of natural gas to customers under various long-term contracts. Company subsidiaries believe that the event was a force majeure, and as a result, the subsidiaries and their joint venture participants declared force majeure under those contracts.

On December 16, 2009, a customer, Burrup Fertilisers Pty Ltd, filed a lawsuit on behalf of itself and certain of its underwriters at Lloyd s of London and other insurers, against the Company and its subsidiaries in Texas state court, asserting claims for negligence, breach of contract, alter ego, single business enterprise, res ipsa loquitur, and gross negligence/exemplary damages. In their Harris County, Texas petition, Cause No. 2009-79834, Burrup Fertilisers and its underwriters and insurers seek to recover unspecified actual damages, cost of repair and replacement, exemplary damages, lost profits, loss of business goodwill, value of the gas lost under the Gas Supply and Purchase Agreement (GSA), interest, and court costs. The Company has filed a motion to dismiss on the ground of *forum non conveniens*, which is pending.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

On March 24, 2011, another customer, Alcoa of Australia Limited ( Alcoa ) filed a lawsuit captioned *Alcoa of Australia Limited vs. Apache Energy Limited, Apache Northwest Pty Ltd, Tap (Harriet) Pty Ltd, and Kufpec Australia Pty Ltd*, Civ. 1481 of 2011, in the Supreme Court of Western Australia. The lawsuit concerns the interruption of deliveries of natural gas to Alcoa under two long-term contracts. Alcoa challenges the declaration of force majeure and the validity of the liquidated damages provisions in the contracts. Alcoa asserts claims based on breach of contract, statutory duties, and duty of care. Alcoa seeks approximately $158 million AUD in general damages or, alternatively, approximately $5.7 million AUD in liquidated damages. On June 20, 2012, the Supreme Court struck out Alcoa s claim that the liquidated damages provisions under two long-term contracts are unenforceable as a penalty and also struck out Alcoa s claim for damages for breach of statutory duty. The Company subsidiaries have filed an appeal in the Supreme Court of Western Australia Court of Appeal asking that Alcoa s remaining tort claim for economic loss be dismissed or, alternatively, struck out. The appeal is pending.

The Company and its subsidiaries do not believe that the Burrup Fertilisers and Alcoa claims have merit and will vigorously pursue their defenses against such claims.

Other customers have threatened to file suit challenging the declaration of force majeure under their contracts. Contract prices under customer contracts are significantly below current spot prices for natural gas in Australia. In the event it is determined that the pipeline explosion was not a force majeure, Company subsidiaries believe that liquidated damages should be the extent of the damages under those long-term contracts with such provisions. Approximately 90 percent of the natural gas volumes sold by Company subsidiaries under long-term contracts have liquidated damages provisions. Contractual liquidated damages under the long-term contracts with such provisions would not be expected to exceed $200 million AUD. No assurance can be given that Burrup Fertilisers and other customers would not assert claims in excess of contractual liquidated damages, and exposure related to such claims is not currently determinable. While an adverse judgment against Company subsidiaries (and the Company, in the case of the Burrup Fertilisers lawsuit) is possible, the Company and Company subsidiaries do not believe any such claims would have merit and plan to vigorously pursue their defenses against any such claims.

In December 2008, the Senate Economics Committee of the Parliament of Australia released its findings from public hearings concerning the economic impact of the gas shortage following the explosion on Varanus Island and the government s response. The Committee concluded, among other things, that the macroeconomic impact to Western Australia will never be precisely known, but cited to a range of estimates from $300 million AUD to $2.5 billion AUD consisting in part of losses alleged by some parties who have long-term contracts with Company subsidiaries (as described above), but also losses alleged by third parties who do not have contracts with Company subsidiaries (but who may have purchased gas that was re-sold by customers or who may have paid more for energy following the explosion or who lost wages or sales due to the inability to obtain energy or the increased price of energy). A timber industry group, whose members do not have a contract with Company subsidiaries, has announced that it intends to seek compensation for its members and their subcontractors from Company subsidiaries for $20 million AUD in losses allegedly incurred as a result of the gas supply shortage following the explosion. In *Johnson Tiles Pty Ltd v. Esso Australia Pty Ltd* [2003] VSC 27 (Supreme Court of Victoria, Gillard J presiding), which concerned a 1998 explosion at an Esso natural gas processing plant at Longford in East Gippsland, Victoria, the Court held that Esso was not liable for $1.3 billion AUD of pure economic losses suffered by claimants that had no contract with Esso, but was liable to such claimants for reasonably foreseeable property damage which Esso settled for $32.5 million AUD plus costs. In reaching this decision the Court held that third-party claimants should have protected themselves from pure economic losses, through the purchase of insurance or the installation of adequate backup measures, in case of an interruption in their gas supply from Esso. While an adverse judgment against Company subsidiaries is possible if litigation is filed, Company subsidiaries do not believe any such claims would have merit and plan to vigorously pursue their defenses against any such claims. Exposure related to any such potential claims is not currently determinable.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

On October 10, 2008, the Australia National Offshore Petroleum Safety Authority (NOPSA) released a self-titled Final Report of the findings of its investigation into the pipeline explosion, prepared at the request of the Western Australian Department of Industry and Resources (DoIR). NOPSA concluded in its report that the evidence gathered to date indicates that the main causal factors in the incident were: (1) ineffective anti-corrosion coating at the beach crossing section of the 12-inch sales gas pipeline, due to damage and/or dis-bondment from the pipeline; (2) ineffective cathodic protection of the wet-dry transition zone of the beach crossing section of the 12-inch sales gas pipeline; and (3) ineffective inspection and monitoring by Company subsidiaries of the beach crossing and shallow water section of the 12-inch sales gas pipeline. NOPSA further concluded that the investigation identified that Apache Northwest Pty Ltd and its co-licensees may have committed offenses under the Petroleum Pipelines Act 1969, Sections 36A & 38(b) and the Petroleum Pipelines Regulations 1970, Regulation 10, and that some findings may also constitute non-compliance with pipeline license conditions.

On May 28, 2009, the Department of Mines and Petroleum (DMP) filed a prosecution notice in the Magistrates Court of Western Australia, charging Apache Northwest Pty Ltd and its co-licensees with failure to maintain a pipeline in good condition and repair under the Petroleum Pipelines Act 1969, Section 38(b). The maximum fine associated with the alleged offense is $50,000 AUD. The Company subsidiary does not believe that the charge has merit and vigorously pursued its defenses, resulting in the dismissal of the prosecution notice by the Magistrates Court of Western Australia on March 29, 2012.

NOPSA states in its report that an application for renewal of the pipeline license (the pipeline license ) covering the area of the Varanus Island facility was granted in May 1985 with 21 years validity, and an application for renewal of the pipeline license was submitted to DoIR by Company subsidiaries in December 2005 and remained pending at the time NOPSA issued its report. The application by Apache Northwest, Kufpec Australia Pty Ltd, and Tap (Harriet) Pty Ltd for renewal and variation of the pipeline license covering the area of the Varanus Island facility was granted on April 19, 2011, by the DMP. The period of the pipeline license is 21 years commencing April 20, 2011.

Company subsidiaries disagree with NOPSA s conclusions and believe that the NOPSA report is premature, based on an incomplete investigation, and misleading. In a July 17, 2008, media statement, DoIR acknowledged, The pipelines and Varanus Island facilities have been the subject of an independent validation report [by Lloyd s Register] which was received in August 2007. NOPSA has also undertaken a number of inspections between 2005 and the present. These and numerous other inspections, audits and reviews conducted by top international consultants and regulators did not identify any warnings that the pipeline had a corrosion problem or other issues that could lead to its failure. Company subsidiaries believe that the explosion was not reasonably foreseeable, and was not within the reasonable control of Company s subsidiaries or able to be reasonably prevented by Company subsidiaries.

On January 9, 2009, the governments of Western Australia and the Commonwealth of Australia announced a joint inquiry to consider the effectiveness of the regulatory regime for occupational health and safety and integrity that applied to operations and facilities at Varanus Island and the role of DoIR, NOPSA, and the Western Australian Department of Consumer and Employment Protection. The joint inquiry s report was published in June 2009.

On May 8, 2009, the government of Western Australia announced that the DMP will carry out the final stage of investigations into the Varanus Island gas explosion. Inspectors were appointed under the Petroleum Pipelines Act to coordinate the final stage of the investigations. That report, prepared by the inspectors in June 2009, was made public by the State government on May 24, 2012. Company subsidiaries disagree with the inspectors June 2009 conclusions. Two other government reports were not published by the State and are not

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

referenced by the inspectors. The Magistrates Court of Western Australia subsequently ordered that both such reports could be released on the basis that the inspectors June 2009 report came with some limitations and the two other government reports together were part and parcel if not the main reason or the only reason certainly a significant contribution to the reason for the matter not proceeding to prosecution and trial. In the first such report, the State s senior investigator said in February 2009 that the prospects of a successful prosecution of Apache for failing to maintain the pipeline would be slight. In the second such report, the State s lead corrosion expert concluded in July 2011 that Apache had reasonable grounds to believe that the pipeline was in good repair prior to the explosion.

***Breton Lawsuit***

On October 4, 2011, plaintiffs filed suit in *Breton Energy, L.L.C. et al. v. Mariner Energy Resources, Inc., et al.*, Case 4:11-cv-03561, in the United States District Court for the Southern District of Texas, Houston Division, seeking compensation from defendants for allegedly depriving plaintiffs of rights to hydrocarbons in a reservoir described by plaintiffs as a common reservoir in West Cameron Blocks 171 and 172 offshore Louisiana in the Gulf of Mexico. In their original petition plaintiffs named, among others, Mariner Energy, Inc. and certain of its affiliates as defendants. On December 12, 2011, plaintiffs filed an amended petition to add as defendants Apache Corporation and Apache Shelf, Inc. as successors to the Mariner interests. On September 27, 2012, the court dismissed plaintiffs claims on various grounds, including for failure to state a claim upon which relief may be granted, while granting plaintiffs leave to amend their complaint within 30 days. On October 29, 2012, the plaintiffs filed an amended complaint. The exposure related to the re-filed lawsuit is not currently determinable. While an adverse judgment against Apache is possible, Apache intends to actively defend the case.

***Escheat Audits***

The State of Delaware, Department of Finance, Division of Revenue (Unclaimed Property), has notified numerous companies, including Apache Corporation, that the State will examine its books and records and those of its subsidiaries and related entities to determine compliance with the Delaware Escheat Laws. The review is being conducted by Kelmar Associates on behalf of the State. At least 30 other states have retained their own consultants and have sent similar notifications. The scope of each state s audit varies. The State of Delaware advises, for example, that the scope of its examination will be for the period 1981 through the present. It is possible that one or more of the State audits could extend to all 50 states. The exposure related to the audits is not currently determinable.

***Burrup-Related Gas Supply Lawsuits***

On May 19, 2011, a lawsuit captioned *Oswal v. Apache Corporation*, Cause No. 2011-30302, in the District Court of Harris County, Texas, was filed in which plaintiff Pankaj Oswal, in his personal capacity and as trustee for the Burrup Trust, asserts claims against the Company under the Australian Trade Practices Act. The Company has filed a motion to dismiss on the ground of *forum non conveniens*, which is pending. This lawsuit is one of a number of legal actions involving the Burrup Fertilisers Pty Ltd (Burrup Fertilisers) ammonia plant in Western Australia (the Burrup plant) founded by Oswal. Oswal s shares, and those of his wife, together representing 65 percent of Burrup Holdings Limited (BHL, which owns Burrup Fertilisers), were offered for sale by externally-appointed administrators in Australia as a result of events of default on loans made to the Oswals by the Australia and New Zealand Banking Group Ltd (ANZ). In the Texas lawsuit, plaintiff Oswal alleges, among other things, that the Company induced him to make investments covering construction cost overruns on the ammonia plant that was completed in 2006. Plaintiff Oswal seeks damages in the amount of $491 million USD. The Company believes that the claims are without merit and intends to vigorously defend against them.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The Texas lawsuit has been consolidated for certain purposes with the Burrup Fertilisers lawsuit arising from the Australia gas pipeline force majeure as described above and the consolidated action has been stayed by the trial court in Houston, Texas, pending resolution of related litigation in Australia, except that the stay of the consolidated action has been lifted partially in order for the Texas court to consider the Company s motions to dismiss on the ground of *forum non conveniens*.

The Texas lawsuit relates to a pending action filed by Tap (Harriet) Pty Ltd (Tap) against Burrup Fertilisers Pty Ltd et al., Civ 2329 of 2009, in the Supreme Court of Western Australia (the Tap action ), seeking a declaratory judgment regarding its contractual rights and obligations under a gas sales agreement between Burrup Fertilisers and the Harriet Joint Venture (comprised of a Company subsidiary and two joint venture partners, Tap and Kufpec Australia Pty Ltd).

As part of the sale process described above, on January 31, 2012, a Company affiliate acquired a 49 percent interest in YPHPL, while Yara Australia Pty Ltd (Yara) increased its interest in YPHPL from 35 percent to 51 percent. Yara will operate the ammonia plant and intends to proceed with development of a technical ammonium nitrate (TAN) plant in the Burrup Peninsula region of Western Australia to be developed by a consortium including YPHPL. YPHPL share ownership continues to be the subject of ongoing litigation in Australia with third parties, including Pankaj and Radhika Oswal. A Company affiliate s existing agreement to supply gas to the ammonia plant has been modified (with, among other things, new pricing, delivery quantities, and term). The new gas supply agreement resolves counterclaims by Burrup Fertilisers against Apache and its affiliate in the Tap action. A Company subsidiary purchased Tap, which then modified its agreement to supply gas to the ammonia plant and resolved both Tap s claims against Burrup Fertilisers and Burrup Fertilisers counterclaims against Tap in the Tap action. If Kufpec does not settle the remaining claims in the Tap action, it is expected that the trial court in the Tap action will issue its ruling in respect of phase 1 of those proceedings, which was tried in September 2011 and concerned construction of the original gas supply agreement.

**Environmental Matters**

The Company, as an owner or lessee and operator of oil and gas properties, is 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 resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. We maintain insurance coverage, which we believe is customary in the industry, although we are not fully insured against all environmental risks.

Apache manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a Company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, the amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to Apache s satisfaction, or agree to assume liability for the remediation of the property. The Company s general policy is to limit any reserve additions to any incidents or sites that are considered probable to result in an expected remediation cost exceeding $300,000. Any environmental costs and liabilities that are not reserved for are treated as an expense when actually incurred. In Apache s estimation, neither these expenses nor expenses related to training and compliance programs are likely to have a material impact on its financial condition.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

As of December 31, 2012, the Company had an undiscounted reserve for environmental remediation of approximately $104 million. Apache is not aware of any environmental claims existing as of December 31, 2012 that have not been provided for or would otherwise have a material impact on its financial position or results of operations. There can be no assurance however, that current regulatory requirements will not change or past non-compliance with environmental laws will not be discovered on the Company s properties.

Apache Canada Ltd. asserted a claim against BP Canada arising out of the acquisition of certain Canadian properties under the parties Partnership Interest and Share Purchase and Sale Agreement dated July 20, 2010. The claim centered on Apache Canada Ltd. s identification of Alleged Adverse Conditions, as that term is defined in the parties agreement, and more specifically the contention that liabilities associated with such conditions were retained by BP Canada as seller. The parties have resolved the matter on commercial terms with no material impact on the Company s financial position, results of operations, or liquidity.

On May 25, 2011, a panel of the Bureau of Ocean Energy Management (BOEMRE, as it was then known) published a report dated May 23, 2011, and titled OCS G-2580, Vermilion Block 380 Platform A, Incidents of Noncompliance. The report concerned the BOEMRE s investigation of a fire on the Vermilion 380 A platform located in the Gulf of Mexico. At the time of the incident, Mariner operated the platform. A small amount of hydrocarbons spilled from the platform into the surrounding water as a result of the incident, and 13 workers were rescued after evacuating the platform. The BOEMRE concluded in its investigation that the fire was caused by Mariner s failure to adequately maintain or operate the platform s heater-treater in a safe condition. The BOEMRE also identified other safety deficiencies on the platform. On December 27, 2011, the Bureau of Safety and Environmental Enforcement (BSEE, successor to BOEMRE) issued several Incidents of Non-Compliance, which may provide the basis for the assessment of civil penalties against Mariner. The Company s subsidiary Apache Deepwater LLC, which acquired Mariner effective November 10, 2010, filed an appeal on August 31, 2012, contesting several of the Incidents of Non-Compliance. It is management s opinion that any loss arising from this matter will not have a material adverse effect on the Company s financial position, results of operations, or liquidity.

**Contractual Obligations**

At December 31, 2012, contractual obligations for drilling rigs, purchase obligations, firm transportation agreements, and long-term operating leases are as follows:

| Net Minimum Commitments | Total | 2013 | 2014-2015 | 2016-2017 | 2018 & Beyond |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Drilling rig commitments[1] | $ 896 | $ 602 | $ 289 | $ 3 | $ 2 |
| Purchase obligations[2] | 2,588 | 1,200 | 1,182 | 184 | 22 |
| Firm transportation agreements[3] | 763 | 148 | 264 | 134 | 217 |
| Office and related equipment[4] | 402 | 49 | 91 | 96 | 166 |
| Other operating lease obligations[5] | 754 | 209 | 316 | 205 | 24 |
| Total Net Minimum Commitments | $ 5,403 | $ 2,208 | $ 2,142 | $ 622 | $ 431 |

(1) Includes day-rate and other contractual agreements with third party service providers for use of drilling, completion, and workover rigs.

(2) Includes contractual obligations to buy or build oil and gas plants and facilities, LNG facilities, seismic and drilling work program commitments, take-or-pay contracts, and hydraulic fracturing services agreements.

(3) Relates to contractual obligations for capacity rights on third-party pipelines.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(4) Includes office and other building rentals and related equipment leases.

(5) Includes commitments required to retain acreage and commitments associated with floating production storage and offloading vessels (FPSOs), compressors, helicopters, and boats.

The table above includes leases for buildings, facilities, and related equipment with varying expiration dates through 2035. Net rental expense was $76 million, $64 million, and $46 million for 2012, 2011, and 2010, respectively.

## 9. RETIREMENT AND DEFERRED COMPENSATION PLANS

Apache Corporation provides retirement benefits to its U.S. employees through the use of multiple plans: a 401(k) savings plan, a money purchase retirement plan, a non-qualified retirement/savings plan, and a non-qualified restorative retirement savings plan. The non-qualified restorative retirement savings plan was implemented January 1, 2012. The 401(k) savings plan provides participating employees the ability to elect to contribute up to 50 percent of eligible compensation, as defined, to the plan with the Company making matching contributions up to a maximum of 8 percent of each employee s annual eligible compensation. In addition, the Company annually contributes 6 percent of each participating employee s annual eligible compensation, as defined, to a money purchase retirement plan. The 401(k) savings plan and the money purchase retirement plan are subject to certain annually-adjusted, government-mandated restrictions that limit the amount of employee and Company contributions. For certain eligible employees, the Company also provides a non-qualified retirement/savings plan or a non-qualified restorative retirement savings plan that allows the deferral of up to 50 percent of each employee s base salary, up to 75 percent of each employee s annual bonus (that accepts employee contributions) and the Company s matching contributions in excess of the government mandated limitations imposed in the 401(k) savings plan and money purchase retirement plan.

Vesting in the Company s contributions in the 401(k) savings plan, the money purchase retirement plan, the non-qualified retirement savings plan and the non-qualified restorative retirement savings plan occurs at the rate of 20 percent for every completed year of employment. Upon a change in control of ownership, immediate and full vesting occurs.

Additionally, Apache Energy Limited, Apache Canada Ltd., and Apache North Sea Limited maintain separate retirement plans, as required under the laws of Australia, Canada, and the U.K., respectively.

The aggregate annual cost to Apache of all U.S. and International savings plans, the money purchase retirement plan, non-qualified retirement/savings plan, and non-qualified restorative retirement savings plan was $117 million, $93 million, and $80 million for 2012, 2011, and 2010, respectively.

Apache also provides a funded noncontributory defined benefit pension plan (U.K. Pension Plan) covering certain employees of the Company s North Sea operations in the U.K. The plan provides defined pension benefits based on years of service and final salary. The plan applies only to employees who were part of the BP North Sea s pension plan as of April 2, 2003, prior to the acquisition of BP North Sea by the Company effective July 1, 2003.

Additionally, the Company offers postretirement medical benefits to U.S. employees who meet certain eligibility requirements. Eligible participants receive medical benefits up until the age of 65, provided the participant remits the required portion of the cost of coverage. The plan is contributory with participants contributions adjusted annually. The postretirement benefit plan does not cover benefit expenses once a covered participant becomes eligible for Medicare.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following tables set forth the benefit obligation, fair value of plan assets and funded status as of December 31, 2012, 2011, and 2010, and the underlying weighted average actuarial assumptions used for the U.K. Pension Plan and U.S. postretirement benefit plan. Apache uses a measurement date of December 31 for its pension and postretirement benefit plans.

| | 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | Pension Benefits | Postretirement Benefits | Pension Benefits | Postretirement Benefits | Pension Benefits | Postretirement Benefits |
| | (In millions) | | | | | |
| **Change in Projected Benefit Obligation** | | | | | | |
| Projected benefit obligation beginning of year | $ 150 | $ 30 | $ 136 | $ 29 | $ 135 | $ 18 |
| Service cost | 5 | 4 | 5 | 3 | 5 | 2 |
| Interest cost | 7 | 1 | 7 | 1 | 7 | 1 |
| Foreign currency exchange rate changes | 7 | | (1) | | (4) | |
| Amendments | | | | | | |
| Actuarial losses (gains) | 14 | 1 | 6 | (2) | (1) | 8 |
| Effect of curtailment and settlements | | | | | | |
| Benefits paid | (6) | (1) | (3) | (1) | (6) | |
| Retiree contributions | | | | | | |
| Projected benefit obligation at end of year | 177 | 35 | 150 | 30 | 136 | 29 |
| **Change in Plan Assets** | | | | | | |
| Fair value of plan assets at beginning of year | 145 | | 135 | | 118 | |
| Actual return on plan assets | 14 | | 4 | | 14 | |
| Foreign currency exchange rates | 6 | | (1) | | (3) | |
| Employer contributions | 11 | 1 | 10 | 1 | 12 | |
| Benefits paid | (6) | (1) | (3) | (1) | (6) | |
| Retiree contributions | | | | | | |
| Fair value of plan assets at end of year | 170 | | 145 | | 135 | |
| **Funded status at end of year** | $ (7) | $ (35) | $ (5) | $ (30) | $ (1) | $ (29) |
| **Amounts recognized in Consolidated Balance Sheet** | | | | | | |
| Current liability | | (1) | | (1) | | (1) |
| Non-current liability | (7) | (34) | (5) | (29) | (1) | (28) |
| | $ (7) | $ (35) | $ (5) | $ (30) | $ (1) | $ (29) |
| **Pre-tax Amounts Recognized in Accumulated Other Comprehensive Income (Loss)** | | | | | | |
| Accumulated (loss) | (32) | (7) | (25) | (6) | (15) | (8) |
| Prior service cost | | | | | | |
| Transition asset (obligation) | | | | | | |
| | $ (32) | $ (7) | $ (25) | $ (6) | $ (15) | $ (8) |
| **Weighted Average Assumptions used as of December 31** | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Discount rate | 4.30% | 3.43% | 4.70% | 4.04% | 5.40% | 4.93% |
| Salary increases | 4.60% | N/A | 4.60% | N/A | 5.00% | N/A |
| Expected return on assets | 4.70% | N/A | 4.85% | N/A | 6.25% | N/A |
| Healthcare cost trend | | | | | | |
| Initial | N/A | 7.25% | N/A | 7.50% | N/A | 8.00% |
| Ultimate in 2022 | N/A | 5.00% | N/A | 5.00% | N/A | 5.00% |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

As of December 31, 2012, 2011, and 2010, the accumulated benefit obligation for the pension plan was $139 million, $119 million, and $107 million, respectively.

Apache s defined benefit pension plan assets are held by a non-related trustee who has been instructed to invest the assets in an equal blend of equity securities and low-risk debt securities. The Company intends that this blend of investments will provide a reasonable rate of return such that the benefits promised to members are provided.

The U.K. Pension Plan policy is to target an ongoing funding level of 100 percent through prudent investments and includes policies and strategies such as investment goals, risk management practices, and permitted and prohibited investments. A breakout of previous allocations for plan asset holdings and the target allocation for the Company s plan assets are summarized below:

| | Target Allocation 2012 | Percentage of Plan Assets at Year-End 2012 | Percentage of Plan Assets at Year-End 2011 |
|---|---|---|---|
| **Asset Category** | | | |
| Equity securities: | | | |
| U.K. quoted equities | 17% | 16% | 17% |
| Overseas quoted equities | 33% | 33% | 31% |
| Total equity securities | 50% | 49% | 48% |
| Debt securities: | | | |
| U.K. Government bonds | 30% | 30% | 30% |
| U.K. corporate bonds | 20% | 20% | 18% |
| Debt securities | 50% | 50% | 48% |
| Cash | 0% | 1% | 4% |
| Total | 100% | 100% | 100% |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The plan s assets do not include any direct ownership of equity or debt securities of Apache. The fair value of plan assets is based upon unadjusted quoted prices for identical instruments in active markets, which is a Level 1 fair value measurement. See discussion of the fair value hierarchy as set forth by ASC 820-10-35 in Note 3 Derivative Instruments And Hedging Activities. The following table presents the fair values of plan assets for each major asset category based on the nature and significant concentration of risks in plan assets at December 31, 2012:

| | Fair Value Measurements Using: | | | |
|---|---|---|---|---|
| | Quoted Price in Active Markets (Level 1) | Significant Other Inputs (Level 2) | Unobservable Inputs (Level 3) | Total Fair Value |
| | (In millions) | | | |
| Equity securities: | | | | |
| U.K. quoted equities[1] | $ 28 | $ | $ | $ 28 |
| Overseas quoted equities[2] | 56 | | | 56 |
| Total equity securities | 84 | | | 84 |
| Debt securities: | | | | |
| U.K. Government bonds[3] | 51 | | | 51 |
| U.K. corporate bonds[4] | 34 | | | 34 |
| Total debt securities | 85 | | | 85 |
| Cash | 1 | | | 1 |
| Fair value of plan assets | $ 170 | $ | $ | $ 170 |

(1) This category comprises U.K. equities, which are benchmarked against the FTSE All-Share Index.

(2) This category includes overseas equities, which comprises 85 percent global equities benchmarked against the MSCI World Index and 15 percent emerging markets benchmarked against the MSCI Emerging Markets Index, both of which have a performance target of 2 percent per annum over the benchmark over a rolling three-year period.

(3) This category includes U.K. Government bonds: 33 percent benchmarked against iBoxx Sterling Overall Gilt Index, with a performance target of 0.75 percent per annum over the benchmark over a rolling three-year period; and 67 percent against the FTSE Actuaries Government Securities Index-Linked Over 5 Years Index.

(4) This category comprises U.K. corporate bonds: 50 percent benchmarked against iBoxx Sterling Overall Non Gilt index with a performance target of 0.75 percent per annum over the benchmark over a rolling three-year period; and 50 percent benchmarked against the iBoxx Sterling Overall Non Gilt Index with a performance target of 0.75 percent per annum over the benchmark over a rolling five year period.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table presents the fair values of plan assets for each major asset category based on the nature and significant concentration of risks in plan assets at December 31, 2011:

| | Fair Value Measurements Using: | | | |
|---|---|---|---|---|
| | Quoted Price in Active Markets (Level 1) | Significant Other Inputs (Level 2) | Unobservable Inputs (Level 3) | Total Fair Value |
| | (In millions) | | | |
| Equity securities: | | | | |
| U.K. quoted equities[1] | $ 24 | $ | $ | $ 24 |
| Overseas quoted equities[2] | 46 | | | 46 |
| Total equity securities | 70 | | | 70 |
| Debt securities: | | | | |
| U.K. Government bonds[3] | 43 | | | 43 |
| U.K. corporate bonds[4] | 26 | | | 26 |
| Total debt securities | 69 | | | 69 |
| Cash | 6 | | | 6 |
| Fair value of plan assets | $ 145 | $ | $ | $ 145 |

(1) This category comprises U.K. equities, which are benchmarked against the FTSE All-Share Index.

(2) This category includes overseas equities, which comprises 85 percent global equities benchmarked against the MSCI World Index and 15 percent emerging markets benchmarked against the MSCI Emerging Markets Index, both of which have a performance target of 2 percent per annum over the benchmark over a rolling three-year period.

(3) This category includes U.K. Government bonds: 72 percent benchmarked against iBoxx Sterling Overall Index, with a performance target of 0.75 percent per annum over the benchmark over a rolling three-year period; and 28 percent against the FTSE Actuaries Government Securities Index-Linked Over 5 Years Index.

(4) This category comprises U.K. corporate bonds benchmarked against the iBoxx Sterling Overall Index.

The expected long-term rate of return on assets assumptions are derived relative to the yield on long-dated fixed-interest bonds issued by the U.K. government (gilts). For equities, outperformance relative to gilts is assumed to be 3.5 percent per year.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions used for the pension and postretirement benefit plans as of December 31, 2012, 2011, and 2010:

| | 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | Pension Benefits | Postretirement Benefits | Pension Benefits | Postretirement Benefits | Pension Benefits | Postretirement Benefits |
| | | | (In millions) | | | |
| **Component of Net Periodic Benefit Costs** | | | | | | |
| Service cost | $ 5 | $ 4 | $ 5 | $ 3 | $ 5 | $ 2 |
| Interest cost | 7 | 1 | 7 | 1 | 7 | 1 |
| Expected return on assets | (7) | | (8) | | (8) | |
| Amortization of actuarial gain (loss) | 1 | | | | 1 | |
| Net periodic benefit cost | $ 6 | $ 5 | $ 4 | $ 4 | $ 5 | $ 3 |
| **Weighted Average Assumptions used to determine Net Period Benefit Cost for the Years ended December 31** | | | | | | |
| Discount rate | 4.70% | 4.04% | 5.40% | 4.93% | 5.70% | 5.56% |
| Salary increases | 4.60% | N/A | 5.00% | N/A | 5.30% | N/A |
| Expected return on assets | 4.85% | N/A | 6.25% | N/A | 6.65% | N/A |
| Healthcare cost trend | | | | | | |
| Initial | | 7.50% | | 8.00% | | 7.50% |
| Ultimate in 2017 | | 5.00% | | 5.00% | | 5.00% |

Assumed health care cost trend rates affect amounts reported for postretirement benefits. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

| | Postretirement Benefits | |
|---|---|---|
| | 1% Increase | 1% Decrease |
| | (In millions) | |
| Effect on service and interest cost components | $ 1 | $ (1) |
| Effect on postretirement benefit obligation | 8 | (6) |

Apache expects to contribute approximately $5 million to its pension plan and $1 million to its postretirement benefit plan in 2013. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

| | Pension Benefits | Postretirement Benefits |
|---|---|---|
| | (In millions) | |
| 2013 | $ 5 | $ 1 |
| 2014 | 6 | 1 |
| 2015 | 7 | 2 |
| 2016 | 7 | 2 |
| 2017 | 6 | 3 |
| Years 2018 2022 | 49 | 18 |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## 10. CAPITAL STOCK

**Common Stock Outstanding**

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Balance, beginning of year | 384,117,643 | 382,391,742 | 336,436,972 |
| Shares issued for stock-based compensation plans: | | | |
| Treasury shares issued | 60,767 | 144,313 | 363,263 |
| Common shares issued | 1,189,693 | 1,581,588 | 1,864,498 |
| Cordillera consideration | 6,272,667 | | |
| Equity offering (BP acquisitions) | | | 26,450,000 |
| Mariner consideration | | | 17,277,009 |
| Balance, end of year | 391,640,770 | 384,117,643 | 382,391,742 |

**Net Income per Common Share**

A reconciliation of the components of basic and diluted net income per common share for the years ended December 31, 2012, 2011, and 2010 is presented in the table below.

| | 2012 | | | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Income | Shares | Per Share | Income | Shares | Per Share | Income | Shares | Per Share |
| | | | | (In millions, except per share amounts) | | | | | |
| **Basic:** | | | | | | | | | |
| Income attributable to common stock | $ 1,925 | 389 | $ 4.95 | $ 4,508 | 384 | $ 11.75 | $ 3,000 | 352 | $ 8.53 |
| **Effect of Dilutive Securities:** | | | | | | | | | |
| Mandatory Convertible Preferred Stock | $ | | | $ 76 | 14 | | $ 32 | 5 | |
| Stock options and other | | 2 | | | 2 | | | 2 | |
| **Diluted:** | | | | | | | | | |
| Income attributable to common stock, including assumed conversions | $ 1,925 | 391 | $ 4.92 | $ 4,584 | 400 | $ 11.47 | $ 3,032 | 359 | $ 8.46 |

The diluted EPS calculation excludes options and restricted shares that were anti-dilutive totaling 4.4 million, 2.5 million, and 2.3 million for the years ended December 31, 2012, 2011, and 2010, respectively. For the year ended December 31, 2012, 14.3 million shares related to the assumed conversion of the Mandatory Convertible Preferred Stock were also anti-dilutive.

**Issuance of Common Stock**

On July 28, 2010, in conjunction with Apache s acquisition of properties from BP, the Company issued 26.45 million shares of common stock at a public offering price of $88 per share. Proceeds, after underwriting discounts and before expenses, from the common stock offering totaled approximately $2.3 billion.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

On November 10, 2010, in connection with the Mariner merger, Apache issued 17.28 million shares of common stock in exchange for Mariner common and restricted stock. The total value of stock consideration, based on the November 10, 2010, closing value on the NYSE of $110.25 per share, was approximately $1.9 billion.

On April 30, 2012, in conjunction with Apache s acquisition of Cordillera, the Company issued 6,272,667 shares of common stock to the sellers.

For further discussion of the BP acquisitions, Mariner merger, and Cordillera acquisition, please see Note 2 Acquisitions and Divestitures.

**Common Stock Dividend**

The Company paid common stock dividends of $0.66 per share in 2012, and $0.60 per share in 2011 and 2010.

**Stock Compensation Plans**

The Company has several stock-based compensation plans, which include stock options, stock appreciation rights, restricted stock, and performance-based share appreciation plans. On May 5, 2011, the Company s shareholders approved the 2011 Omnibus Equity Compensation Plan (the 2011 Plan), which is intended to provide eligible employees with equity-based incentives. The 2011 Plan provides for the granting of Incentive Stock Options, Non-Qualified Stock Options, Performance Awards, Restricted Stock, Restricted Stock Units, Stock Appreciation Rights, or any combination of the foregoing. Previously-approved plans remain in effect solely for the purpose of governing grants still outstanding that were issued prior to approval of the 2011 Plan. All new grants are issued from the 2011 Plan.

For 2012, 2011, and 2010, stock-based compensation expensed was $167 million, $113 million, and $164 million ($119 million, $73 million, and $106 million after tax), respectively. Costs related to the plans are capitalized or expensed based on the nature of each employee s activities. A description of the Company s stock-based compensation plans and related costs follows:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| Stock-based compensation expensed: | | | |
| General and administrative | $ 104 | $ 69 | $ 98 |
| Lease operating expenses | 63 | 44 | 66 |
| Stock-based compensation capitalized | 67 | 42 | 71 |
| | $ 234 | $ 155 | $ 235 |

***Stock Options***

As of December 31, 2012, officers and employees held options to purchase shares of the Company s common stock under one or more of the employee stock option plans adopted in 1998, 2000, and 2005 (collectively, the Stock Option Plans), as well as the 2007 Omnibus Equity Compensation Plan (the 2007 Plan), and the 2011 Plan discussed above (together, the Omnibus Plans). New shares of Company stock will be issued for employee stock option exercises; however, under the 2000 Stock Option Plan, shares of treasury stock are

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

used for employee stock option exercises to the extent treasury stock is held. Under the Stock Option Plans and the Omnibus Plans, the exercise price of each option equals the closing price of Apache s common stock on the date of grant. Options generally become exercisable ratably over a four-year period and expire 10 years after granted. The Omnibus Plans and all of the Stock Option Plans, except for the 2000 Stock Option Plan, were submitted to and approved by the Company s shareholders.

A summary of stock options issued and outstanding under the Stock Option Plans and the Omnibus Plans is presented in the table and narrative below:

| | 2012 | |
|---|---|---|
| | Shares Under Option (In thousands) | Weighted Average Exercise Price |
| Outstanding, beginning of year | 6,092 | $ 91.96 |
| Granted | 2,072 | 82.65 |
| Exercised | (311) | 56.15 |
| Forfeited or expired | (280) | 102.90 |
| Outstanding, end of year[1] | 7,573 | 90.47 |
| Expected to vest[1] | 2,900 | 96.23 |
| Exercisable, end of year[1] | 3,922 | 85.55 |
| Available for grant, end of year | 15,498 | |
| Weighted average fair value of options granted during the year | $ 26.41 | |

[1] As of December 31, 2012, the weighted average remaining contractual life for options outstanding, expected to vest, and exercisable is 6.7 years, 8.6 years, and 5.0 years, respectively. The aggregate intrinsic value of options outstanding, expected to vest, and exercisable at year-end was $19 million, $0, and $19 million, respectively. The weighted-average grant-date fair value of options granted during the years 2012, 2011, and 2010 was $26.41, $42.20, and $34.12, respectively.

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table. Expected volatilities are based on historical volatility of the Company s common stock and other factors. The expected dividend yield is based on historical yields on the date of grant. The expected term of stock options granted represents the period of time that the stock options are expected to be outstanding and is derived from historical exercise behavior, current trends, and values derived from lattice-based models. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant.

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Expected volatility | 34.94% | 34.47% | 35.02% |
| Expected dividend yields | 0.82% | 0.47% | 0.60% |
| Expected term (in years) | 5.5 | 5.5 | 5.5 |
| Risk-free rate | 0.78% | 1.95% | 2.31% |

The intrinsic value of options exercised during 2012, 2011, and 2010 was approximately $12 million, $50 million and $62 million, respectively. The cash received from exercise of options during 2012 was approximately $17 million. The Company realized an additional tax benefit of approximately $2 million for the amount of

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

intrinsic value in excess of compensation cost recognized in 2012. As of December 31, 2012, the total compensation cost related to non-vested options not yet recognized was $90 million, which will be recognized over the remaining vesting period of the options.

***Stock Appreciation Rights***

For some non-executive employees, the Company issued stock appreciation rights (SARs) in lieu of stock options. The SARs vest ratably over four years and are settled in cash upon exercise throughout their ten-year life. In 2012, the Company issued 180,555 SARs with a weighted-average exercise price of $82.63 under the 2011 Omnibus Plan. Additionally, in 2003 and 2004 the Company issued 1,809,060 SARs with a weighted-average exercise price of $42.68 and 1,334,300 SARs with a weighted-average exercise price of $28.78, respectively, under the 2003 Stock Appreciation Rights Plan. As of December 31, 2012, a total of 583,688 SARs were outstanding, of which 413,582 were exercisable. Since SARs are cash-settled, the Company records compensation expense based on the fair value of the SARs at the end of each period. As of year-end, the weighted-average fair value of SARs outstanding was $36.20 based on the Black-Scholes valuation methodology using assumptions comparable to those discussed above. During 2012, 60,523 SARs were exercised. The aggregate of cash payments made to settle SARs was $3 million.

***Restricted Stock and Restricted Stock Units***

The Company has restricted stock and restricted stock unit plans for eligible employees including officers. The programs created under the Omnibus Plans have been approved by Apache s Board of Directors. In 2012, the Company awarded 1,219,886 restricted stock units at a weighted-average per-share market price of $85.67. In 2011 and 2010, the Company awarded 887,851 and 1,143,989 restricted stock units at a weighted-average per-share market price of $124.16 and $103.88, respectively. The value of the stock issued was established by the market price on the date of grant and is being recorded as compensation expense ratably over the vesting terms. During 2012, 2011, and 2010, $74 million ($48 million after tax), $76 million ($49 million after tax), and $73 million ($47 million after tax), respectively, was charged to expense. In 2012, 2011, and 2010, $25 million, $28 million, and $28 million was capitalized, respectively. As of December 31, 2012, there was $151 million of total unrecognized compensation cost related to 2,163,564 unvested restricted stock units. The weighted-average remaining life of unvested restricted stock units is approximately 1.4 years.

The fair value of the awards vested during 2012, 2011 and 2010 was approximately $114 million, $85 million, and $69 million, respectively. A summary of restricted stock activity for the year ended December 31, 2012, is presented below.

| | Shares (In thousands) | Weighted-Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at January 1, 2012 | 2,115 | $ 109.63 |
| Granted | 1,220 | 85.67 |
| Vested | (1,053) | 107.76 |
| Forfeited | (118) | 102.82 |
| Non-vested at December 31, 2012 | 2,164 | 97.34 |

***Conditional Restricted Stock Units***

To provide long-term incentives for Apache employees to deliver competitive returns to the Company s stockholders, in January 2012, 2011, and 2010 the Company granted conditional restricted stock units to eligible

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total shareholder return of Apache common stock as compared to a designated peer group during a three-year performance period. Should any restricted stock units be awarded at the end of the three-year performance period, 50 percent of restricted stock units awarded will immediately vest, and an additional 25 percent will vest on succeeding anniversaries of the end of the performance period. Three conditional restricted stock unit programs have been approved, as described below:

In November 2009 the Company s Board of Directors approved the 2010 Performance Program, pursuant to the 2007 Plan. In January 2010 eligible employees received initial conditional restricted stock unit awards totaling 541,440 units. Based on measurement of total shareholder return relative to the designated peer group at December 31, 2012, zero shares were awarded and all unvested conditional restricted stock units were cancelled.

In November 2010 the Company s Board of Directors approved the 2011 Performance Program, pursuant to the 2007 Plan. In January 2011 eligible employees received initial conditional restricted stock unit awards totaling 585,811 units. A total of 503,884 units were outstanding at December 31, 2012, from which a minimum of zero and a maximum of 1,259,710 units could be awarded.

In January 2012 the Company s Board of Directors approved the 2012 Performance Program, pursuant to the 2011 Plan. In January 2012 eligible employees received initial conditional restricted stock unit awards totaling 851,985 units. A total of 802,390 units were outstanding at December 31, 2012, from which a minimum of zero and a maximum of 2,005,975 units could be awarded.

The fair value cost of the awards was estimated on the date of grant and is being recorded as compensation expense ratably over the vesting terms. During 2012, 2011, and 2010, $47 million ($31 million after tax), $12 million ($8 million after tax), and $7 million ($4 million after tax), respectively, was charged to expense. During 2012, 2011, and 2010, $21 million, $5 million, and $3 million was capitalized, respectively. As of December 31, 2012, there was $72 million of total unrecognized compensation cost related to 1,306,274 unvested conditional restricted stock units. The weighted-average remaining life of the unvested conditional restricted stock units is approximately 2.4 years.

| | Shares (In thousands) | Weighted-Average Grant-Date Fair Value[1] |
|---|---|---|
| Non-vested at January 1, 2012 | 1,019 | $ 115.10 |
| Granted | 852 | 70.30 |
| Vested | (1) | 100.81 |
| Forfeited | (564) | 132.45 |
| Non-vested at December 31, 2012 | 1,306 | 78.40 |

(1) The fair value of each conditional restricted stock unit award is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all grants made under the plan: (i) a three-year continuous risk-free interest rate; (ii) a constant volatility assumption based on the historical realized stock price volatility of the Company and the designated peer group; and (iii) the historical stock prices and expected dividends of the common stock of the Company and its designated peer group.

In January 2013 the Company s Board of Directors approved the 2013 Performance Program, pursuant to the 2011 Plan, with terms similar to the 2012 Performance Program. Eligible employees received initial conditional restricted stock unit awards totaling 1,232,176 units, with the ultimate number of restricted stock units to be awarded ranging from zero to a maximum of 2,464,352 units.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

***Share Appreciation Plans***

The Company previously utilized share appreciation plans to provide incentives for substantially all full-time employees and officers to increase Apache s share price within a stated measurement period. To achieve the payout, the Company s stock price must close at or above a stated threshold for 10 out of any 30 consecutive trading days before the end of the stated period. Shares of Apache common stock contingently issuable under the plans are excluded from the computation of income per common share until the stated goals are met as described below.

Since 2005, two share appreciation plans have been approved. A summary of these plans is as follows:

On May 7, 2008, the Stock Option Plan Committee of the Company s Board of Directors, pursuant to the 2007 Plan, approved the 2008 Share Appreciation Program with a target to increase Apache s share price to $216 by the end of 2012 and an interim goal of $162 to be achieved by the end of 2010. The interim target of $162 was not met by the end of 2010, and the related awards were cancelled. The $216 share price target was not met by the end of 2012, and all remaining awards under the 2008 Share Appreciation Program were cancelled.

On May 5, 2005, the Company s stockholders approved the 2005 Share Appreciation Plan, with a target to increase Apache s share price to $108 by the end of 2008 and an interim goal of $81 to be achieved by the end of 2007. Apache s share price exceeded the interim $81 threshold for the 10-day requirement as of June 14, 2007. Apache s share price exceeded the $108 threshold for the 10-day requirement as of February 29, 2008. Awards under the plan were payable in four equal annual installments to eligible employees remaining with the Company.

A summary of the number of shares contingently issuable as of December 31, 2012, 2011, and 2010 for each plan is presented in the table below:

| | | Shares subject to Conditional Grants | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| | | **(In thousands)** | |
| **2008 Share Appreciation Program** | | | |
| Outstanding, beginning of year | 1,372 | 1,485 | 2,592 |
| Granted | | | 25 |
| Forfeited or cancelled | (1,372) | (113) | (1,132) |
| Outstanding, end of year[1] | | 1,372 | 1,485 |
| Weighted-average value of grants outstanding[2] | $ | $ 71.28 | $ 71.16 |
| **2005 Share Appreciation Plan** | | | |
| Outstanding, beginning of year | | 400 | 1,103 |
| Issued[3] | | (398) | (678) |
| Forfeited or cancelled | | (2) | (25) |
| Outstanding, end of year | | | 400 |
| Weighted-average value of grants outstanding[4] | $ | $ | $ 21.64 |

(1) Represents shares issuable upon target achievement and vesting of awards related to the $216 and $162 per share price goals of zero shares at December 31, 2012; 1,372,190 and zero shares, respectively, at December 31, 2011; and 1,485,210 and zero shares, respectively, at December 31, 2010.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(2) The fair value of each Share Price Goal conditional grant is estimated as of the date of grant using a Monte Carlo simulation with the following weighted-average assumptions used for all grants made under the plan: (i) risk-free interest rate of 2.98 percent; (ii) expected volatility of 28.31 percent; and (iii) expected dividend yield of .54 percent.

(3) The total fair value of these awards vested during 2011 and 2010 was approximately $9 million and $18 million, respectively.

(4) The fair value of each Share Price Goal conditional grant is estimated as of the date of grant using a Monte Carlo simulation with the following weighted-average assumptions used for all grants made under the plan: (i) risk-free interest rate of 3.95 percent; (ii) expected volatility of 28.02 percent; and (iii) expected dividend yield of .57 percent.

The Company recognizes over the requisite service period the fair value cost determined at the grant date based on numerous assumptions, including an estimate of the likelihood that Apache s stock price will achieve these thresholds and the expected forfeiture rate. If a price target is not met before the end of the stated achievement period, any unamortized expense must be immediately recognized. Since the $162 and $216 price targets of the 2008 Share Appreciation Program were not met prior to the end of the stated achievement periods, Apache recognized $27 million of unamortized expense and $14 million of unamortized capital costs on December 31, 2010, and $16 million of unamortized expense and $8 million of unamortized capital costs on December 31, 2012, respectively. The Company recognized total expense and capitalized costs for the 2008 Share Appreciation Program of $181 million and as of year-end 2012 had no unamortized cost remaining. As of March 2011, the Company had recognized $79 million of total expense and capitalized costs for the 2005 Share Appreciation Plan and had no unamortized costs remaining. A summary of the amounts recognized as expense and capitalized costs for each plan are detailed in the table below:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In millions) | |
| **2008 Share Appreciation Program** | | | |
| Compensation expense | $ 22 | $ 8 | $ 49 |
| Compensation expense, net of tax | 14 | 5 | 31 |
| Capitalized costs | 12 | 5 | 27 |
| **2005 Share Appreciation Plan** | | | |
| Compensation expense | | $ 1 | $ 6 |
| Compensation expense, net of tax | | 1 | 4 |
| Capitalized costs | | 1 | 3 |

**Preferred Stock**

The Company has 10,000,000 shares of no par preferred stock authorized, of which 25,000 shares have been designated as Series A Junior Participating Preferred Stock (the Series A Preferred Stock) and 1.265 million shares as 6.00-percent Mandatory Convertible Preferred Stock, Series D (the Series D Preferred Stock).

***Series A Preferred Stock***

In December 1995, the Company declared a dividend of one right (a Right) for each 2.31 shares (adjusted for subsequent stock dividends and a two-for-one stock split) of Apache common stock outstanding on January 31, 1996. Each full Right entitles the registered holder to purchase from the Company one ten-thousandth (1/10,000) of a share of Series A Preferred Stock at a price of $100 per one ten-thousandth of a share,

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

subject to adjustment. The Rights are exercisable 10 calendar days following a public announcement that certain persons or groups have acquired 20 percent or more of the outstanding shares of Apache common stock or 10 business days following commencement of an offer for 30 percent or more of the outstanding shares of Apache s outstanding common stock (flip-in event); each Right will become exercisable for shares of Apache s common stock at 50 percent of the then-market price of the common stock. If a 20-percent shareholder of Apache acquires Apache, by merger or otherwise, in a transaction where Apache does not survive or in which Apache s common stock is changed or exchanged (flip-over event), the Rights become exercisable for shares of the common stock of the Company acquiring Apache at 50 percent of the then-market price for Apache common stock. Any Rights that are or were beneficially owned by a person who has acquired 20 percent or more of the outstanding shares of Apache common stock and who engages in certain transactions or realizes the benefits of certain transactions with the Company will become void. If an offer to acquire all of the Company s outstanding shares of common stock is determined to be fair by Apache s board of directors, the transaction will not trigger a flip-in event or a flip-over event. The Company may also redeem the Rights at $.01 per Right at any time until 10 business days after public announcement of a flip-in event. 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. Unless the Rights have been previously redeemed, all shares of Apache common stock issued by the Company after January 31, 1996 will include Rights. Unless and until the Rights become exercisable, they will be transferred with and only with the shares of Apache common stock.

***Series D Preferred Stock***

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. The Company received proceeds of approximately $1.2 billion, after underwriting discounts and before expenses, from the sale.

Each Preferred Share has an initial liquidation preference of $1,000 per share (equivalent to $50 liquidation preference per depositary share). When and if declared by the Board of Directors, Apache will pay cumulative dividends on each Preferred Share at a rate of 6.00 percent per annum on the initial liquidation preference. Dividends will be paid in cash quarterly on February 1, May 1, August 1, and November 1 of each year, commencing on November 1, 2010, and until and including May 1, 2013. The final dividend payment on August 1, 2013, may be paid or delivered, as the case may be, in cash, shares of Apache common stock, or a combination thereof, at the election of the Company.

The Preferred Shares may be converted, at the option of the holder, into 9.164 shares, subject to adjustment, of Apache common stock at any time prior to July 15, 2013. If not converted prior to that time, each Preferred Share will automatically convert on August 1, 2013, into a minimum of 9.164 or a maximum of 11.364 shares, each subject to adjustment, of Apache common stock depending on the volume-weighted average price per share of Apache s common stock over the ten trading day period ending on, and including, the third scheduled trading day immediately preceding the mandatory conversion. Upon conversion, a minimum of 11.6 million Apache common shares and a maximum of 14.4 million common shares will be issued.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## 11. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of accumulated other comprehensive income (loss) consists of the following:

| | For the Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In millions) | |
| Currency translation adjustment[1] | $ (109) | $ (109) | $ (109) |
| Unrealized gain (loss) on derivatives (Note 3) | (6) | 114 | (19) |
| Unfunded pension and postretirement benefit plan | (16) | (14) | (13) |
| Accumulated other comprehensive loss | $ (131) | $ (9) | $ (141) |

[1] Currency translation adjustments resulting from translating the Canadian subsidiaries financial statements into U.S. dollar equivalents, prior to adoption of the U.S. dollar as their functional currency, were reported separately and accumulated in other comprehensive income (loss).

## 12. MAJOR CUSTOMERS

In 2012, 2011, and 2010, purchases by Royal Dutch Shell plc and its subsidiaries accounted for 20 percent, 11 percent, and 15 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.

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## 13. BUSINESS SEGMENT INFORMATION

Apache is engaged in a single line of business. Both domestically and internationally, the Company explores for, develops, and produces natural gas, crude oil and natural gas liquids. At December 31, 2012, the Company had production in six countries: the United States, Canada, Egypt, Australia, offshore the United Kingdom (U.K.) in the North Sea, and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities. Financial information for each country is presented below:

| | United States | Canada | Egypt | Australia | North Sea (In millions) | Argentina | Other International | Total |
|---|---|---|---|---|---|---|---|---|
| **2012** | | | | | | | | |
| Oil and gas production revenues | $ 6,226 | $ 1,322 | $ 4,554 | $ 1,575 | $ 2,751 | $ 519 | $ | $ 16,947 |
| Operating Expenses: | | | | | | | | |
| Depreciation, depletion, and amortization | | | | | | | | |
| Recurring | 2,056 | 594 | 925 | 466 | 914 | 228 | | 5,183 |
| Additional | | 1,883 | | | | | 43 | 1,926 |
| Asset retirement obligation accretion | 112 | 41 | | 17 | 58 | 4 | | 232 |
| Lease operating expenses | 1,386 | 458 | 410 | 215 | 315 | 184 | | 2,968 |
| Gathering and transportation | 69 | 163 | 39 | | 24 | 8 | | 303 |
| Taxes other than income | 292 | 50 | 14 | 11 | 451 | 44 | | 862 |
| Operating Income (Loss)(1) | $ 2,311 | $ (1,867) | $ 3,166 | $ 866 | $ 989 | $ 51 | $ (43) | 5,473 |
| Other Income (Expense): | | | | | | | | |
| Other | | | | | | | | 131 |
| General and administrative | | | | | | | | (531) |
| Merger, acquisitions & transition | | | | | | | | (31) |
| Financing costs, net | | | | | | | | (165) |
| Income Before Income Taxes | | | | | | | | $ 4,877 |
| Net Property and Equipment | $ 28,552 | $ 6,640 | $ 5,151 | $ 5,312 | $ 5,927 | $ 1,621 | $ 77 | $ 53,280 |
| Total Assets | $ 31,175 | $ 7,142 | $ 7,311 | $ 6,280 | $ 6,874 | $ 1,835 | $ 120 | $ 60,737 |
| Additions to Net Property and Equipment | $ 9,586 | $ 1,096 | $ 1,153 | $ 1,581 | $ 1,104 | $ 337 | $ 98 | $ 14,955 |
| **2011** | | | | | | | | |
| Oil and gas production revenues | $ 6,103 | $ 1,617 | $ 4,791 | $ 1,734 | $ 2,091 | $ 474 | $ | $ 16,810 |
| Operating Expenses: | | | | | | | | |
| Depreciation, depletion, and amortization | | | | | | | | |
| Recurring | 1,684 | 546 | 818 | 440 | 409 | 198 | | 4,095 |
| Additional | | | | | | | 109 | 109 |
| Asset retirement obligation accretion | 97 | 26 | | 10 | 17 | 4 | | 154 |
| Lease operating expenses | 1,167 | 470 | 398 | 197 | 208 | 165 | | 2,605 |
| Gathering and transportation | 64 | 165 | 35 | | 25 | 7 | | 296 |
| Taxes other than income | 259 | 51 | 13 | 9 | 539 | 28 | | 899 |
| Operating Income (Loss)(1) | $ 2,832 | $ 359 | $ 3,527 | $ 1,078 | $ 893 | $ 72 | $ (109) | 8,652 |
| Other Income (Expense): | | | | | | | | |
| Other | | | | | | | | 78 |
| General and administrative | | | | | | | | (459) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Merger, acquisitions & transition | | | | | | | | (20) |
| Financing costs, net | | | | | | | | (158) |
| Income Before Income Taxes | | | | | | | | $ 8,093 |
| Net Property and Equipment | $ 21,038 | $ 8,022 | $ 4,923 | $ 4,194 | $ 5,737 | $ 1,512 | $ 22 | $ 45,448 |
| Total Assets | $ 23,499 | $ 8,816 | $ 6,656 | $ 4,681 | $ 6,600 | $ 1,766 | $ 33 | $ 52,051 |
| Additions to Net Property and Equipment | $ 3,854 | $ 1,288 | $ 1,015 | $ 1,140 | $ 4,175 | $ 374 | $ 73 | $ 11,919 |

**APACHE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | United States | Canada | Egypt | Australia | North Sea | Argentina | Other International | Total |
|---|---|---|---|---|---|---|---|---|
| | | | | (In millions) | | | | |
| **2010** | | | | | | | | |
| Oil and gas production revenues | $ 4,300 | $ 1,074 | $ 3,372 | $ 1,459 | $ 1,606 | $ 372 | $ | $ 12,183 |
| Operating Expenses: | | | | | | | | |
| Depreciation, depletion, and amortization | | | | | | | | |
| Recurring | 1,163 | 294 | 754 | 408 | 304 | 160 | | 3,083 |
| Asset retirement obligation accretion | 62 | 23 | | 9 | 15 | 2 | | 111 |
| Lease operating expenses | 924 | 334 | 298 | 185 | 168 | 123 | | 2,032 |
| Gathering and transportation | 42 | 75 | 31 | | 25 | 5 | | 178 |
| Taxes other than income | 190 | 35 | 10 | 11 | 422 | 22 | | 690 |
| Operating Income[(1)] | $ 1,919 | $ 313 | $ 2,279 | $ 846 | $ 672 | $ 60 | $ | 6,089 |
| Other Expense: | | | | | | | | |
| Other | | | | | | | | (91) |
| General and administrative | | | | | | | | (380) |
| Merger, acquisitions & transition | | | | | | | | (183) |
| Financing costs, net | | | | | | | | (229) |
| Income Before Income Taxes | | | | | | | | $ 5,206 |
| Net Property and Equipment | $ 19,069 | $ 7,497 | $ 4,726 | $ 3,495 | $ 1,970 | $ 1,336 | $ 58 | $ 38,151 |
| Total Assets | $ 21,326 | $ 8,273 | $ 6,036 | $ 3,831 | $ 2,362 | $ 1,537 | $ 60 | |