APACHE CORP
Form 10-K
February 28, 2011

Table of Contents

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

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-4300

APACHE CORPORATION
(Exact name of registrant as specified in its charter)

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

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400
(Address of principal executive offices)
Registrant s telephone number, including area code **(713) 296-6000**
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.625 par value	New York Stock Exchange, Chicago Stock Exchange and NASDAQ National Market
Preferred Stock Purchase Rights	New York Stock Exchange and Chicago Stock Exchange
Apache Finance Canada Corporation 7.75% Notes Due 2029 Irrevocably and Unconditionally Guaranteed by Apache Corporation	New York Stock Exchange
Depositary Shares Representing a 1/20th Interest in a Share of 6.00% Mandatory	New York Stock Exchange

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 þ No o

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 o No þ

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 þ No o

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 þ No o

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. þ

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. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2010	$ 28,439,311,280
Number of shares of registrant s common stock outstanding as of January 31, 2011	382,752,217

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s proxy statement relating to registrant s 2011 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

TABLE OF CONTENTS

DESCRIPTION

Table of Contents

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 Bbl 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, which is approximately equal to one Mcf.

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 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 seven countries: the U.S., Canada, Egypt, Australia, offshore the United Kingdom in the North Sea, Argentina, and Chile.

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 May 25, 2010, 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 Apache s corporate governance (including our Code of Business Conduct and Governance Principles) and documents Apache files 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 also 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.

We hold interests in many of our U.S., Canadian and other international properties through subsidiaries. Properties to which we refer in this document may be held by those subsidiaries. We treat all operations as one line of business. 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 stockholders. Apache s long-term perspective has many dimensions, with the following core strategic components:

balanced portfolio of core assets;

conservative capital structure; and

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 investment rates of return for the benefit of our shareholders. We have increased reserves 22 out of the last 25 years and production 30 out of the past 32 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. In the years immediately prior to 2010, we were relatively absent from the acquisition market. We believed the market was overheated as oil and gas prices spiked, and the opportunities we identified did not meet our criteria for risk, reward, rate of return and/or growth potential. We built our cash position while drilling from our existing inventory of prospects and waiting for the right transactions to add to our portfolio. During 2010 we completed more than $11 billion in acquisitions and made significant progress with exploitation on existing core properties.

The current-year acquisitions fit well with our long-term strategy of maintaining a balanced portfolio of core assets. They included high-quality assets with a diversity of geologic and geographic risk, product mix and reserve life. The properties are strategically positioned with our existing infrastructure and play to the strengths that come with our experience operating in the Permian Basin, Canada and Gulf of Mexico (GOM). The Mariner merger also provided a strategic position in the deepwater GOM, which is relatively under explored and oil prone and gives Apache exposure to significant domestic oil reserves. The transactions drove a 42 percent, or 10 million acre, year-over-year increase in our undeveloped gross acres, adding to our inventory of future drilling and exploration opportunities.

2010 Acquisitions

North America

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.

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

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.

International

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

Balanced Portfolio of Core Assets

A cornerstone of our long-term strategy is balancing our portfolio of assets through diversity of geologic risk, geographic risk, hydrocarbon mix (crude oil versus natural gas), and reserve life in order to achieve consistency in results. Our portfolio of geographic locations provides variation of all of these factors. We have exploration and production operations in seven countries, spanning five continents: the Gulf Coast, Permian and Central regions of the U.S., Canada, Egypt, the U.K. North Sea, Australia, Argentina and on the Chilean side of the island of Tierra del Fuego. Our 2010 acquisitions added to our asset base in the United States, Canada, and Egypt.

In addition, each of our producing regions has achieved an economy of scale providing a vehicle for cost-effective base production and a combination of lower- and medium-risk drilling opportunities. The net cash provided by operating activities (cash flows) generated by our current production base funds our drilling and development capital program, giving us the ability to pursue new exploration targets over our 35 million gross undeveloped acres across the globe and develop our pipeline of exploration discoveries. Those developments will fund the next round of exploration activities and development programs.

In 2010:

- No single region contributed more than 28 percent of our equivalent production or revenue.
- No single region held more than 26 percent of our year-end estimated proved reserves.

Table of Contents

The mixture of reserve life (estimated reserves divided by annual production) in our countries, which translates into balance in the timing of returns on our investments, ranges from as short as five years to as long as 25 years.

Our balanced product mix provides a measure of protection against price deterioration in a given product while retaining upside potential through a significant increase in either commodity price. In 2010 crude oil and liquids provided 52 percent of our production and 77 percent of our revenue.

At year-end our estimated proved reserves were 44 percent crude oil and liquids and 56 percent natural gas.

Our international gas portfolio, which accounted for 19 percent of our 2010 worldwide equivalent production, positions us to take advantage of increasing prices in Argentina and Australia.

Conservative Capital Structure

Maintaining a strong balance sheet and financial flexibility is a core strategic component of our long-term strategy. We believe our balance sheet, and the financial flexibility it provides, is one of our most important strategic assets. Maintaining a strong balance sheet underpins our ability to weather commodity price volatility and has enabled us to deliver long-term production and reserves growth throughout the cycles of our industry. It is also key in positioning us to pursue value-creating acquisitions when opportunities arise, as they did in 2010.

We exited 2010 with a debt-to-capitalization ratio of 25 percent, an increase of only one percent despite current year capital investments of $17 billion, and $2.4 billion of available committed borrowing capacity.

Rate of Return Focus

Another core component to our long-term strategy is focusing on rate-of-return. We do so through centralized management and incentive systems, decentralized decision making, strict cost control, and the creative application of technology.

Our centralized management and incentive systems provide a uniform process of measuring success across Apache. They incentivize high rate-of-return activities but allow for appropriate risk-taking to drive future growth. Results of operations and rates of return on invested capital are measured monthly, reviewed with management quarterly, and utilized to determine annual performance awards. We review capital allocations, at least quarterly, utilizing estimates of internally-generated cash flow. We do this through a disciplined and focused process that includes analyzing current economic conditions, projected rates of return on internally-generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects or, occasionally, new core areas that could enhance our portfolio.

We also use technology to reduce risk, decrease time and costs and maximize recoveries from reservoirs. Apache scientists and engineers have been granted numerous patents for a range of inventions, from systems used for interpreting seismic data and processing well logs to improvements in drilling and completion techniques.

One such example is a manifold developed for our Horn River Shale gas play in northeast British Columbia, where Apache is employing pad-drilling technology. Apache engineers developed and applied for a patent on a manifold that can connect all horizontal wells on a single pad, driving down costs by reducing non-productive time on our 24-hour-a-day hydraulic fracturing operations. This technology will reduce costs and increase Apache s rate of return on potentially thousands of future wells across our leasehold.

At our Forties field in the North Sea, Apache is using techniques that bring together many sources of data to give an accurate view of the current state of the field and identify likely places to find unswept oil deposits. Four-dimensional modeling, which uses reservoir engineering data and a series of 3-D seismic surveys, is utilized by Apache to create a time-lapse picture that shows where oil remains after more than 35 years of production. The latest model of the reservoir highlights the potential for stranded oil accumulations and enhances the success of the ongoing drilling program as well as identifies new potential drilling locations.

For a more in-depth discussion of our 2010 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.

Table of Contents

Geographic Area Overviews

We currently have exploration and production interests in seven countries: the U.S., Canada, Egypt, Australia, offshore the United Kingdom in the North Sea, Argentina, and Chile.

The following table sets out a brief comparative summary of certain key 2010 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2010 Production (In MMboe)	Percentage of Total 2010 Production	2010 Production Revenue (In millions)	12/31/10 Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	2010 Gross New Wells Drilled	2010 Gross New Productive Wells Drilled
United States	84.7	35%	$ 4,300	1,304	44%	410	388
Canada	30.5	13	1,074	757	26	182	173
Total North America	115.2	48	5,374	2,061	70	592	561
Egypt	59.0	24	3,372	307	10	204	177
Australia	28.9	12	1,459	314	11	31	23
North Sea	20.9	9	1,606	155	5	20	12
Argentina	16.0	7	372	116	4	56	52
Other International						1	1
Total International	124.8	52	6,809	892	30	312	265
Total	240.0	100%	$ 12,183	2,953	100%	904	826

North America

Apache s North American asset base comprises the Gulf Coast, Permian and Central regions of the U.S. and its operations in Canada. In 2010 our North America assets contributed 48 percent of our production and 44 percent of our oil and gas production revenues. At year-end 70 percent of our estimated proved reserves were located in North America.

United States

Overview We have 9.7 million gross acres across the U.S., approximately half of which is undeveloped. Approximately 30 percent of the undeveloped acreage is held-by-production. Our U.S. assets are located in the Gulf Coast, Permian and Central regions. The three regions provide our U.S. asset base with a balance of hydrocarbon mix and reserve life. In 2010 48 percent of our U.S. production and 58 percent of our U.S. year-end reserves were oil and liquids. In addition, the reserve life of our U.S. regions ranged from nine to 30 years with the Gulf Coast region s shorter-lived reserves balancing longer-lived reserves in the Central and Permian regions. In 2010 35 percent of

Apache s equivalent production and 44 percent of Apache s total year-end reserves were in the U.S.

Gulf Coast Region Our Gulf Coast assets are primarily located in and along the Gulf of Mexico, in the areas on- and offshore Texas and Louisiana. In 2010 the Gulf Coast region contributed approximately 19 percent of our worldwide production and revenues, predominately from offshore properties. Apache s Gulf Coast operations grew significantly during the year with the June acquisition of Devon s Gulf of Mexico shelf properties and the addition of properties with the Mariner merger in November 2010. These transactions were aligned with our long-term core strategy of maintaining a balanced portfolio of assets. The region accounted for nearly 13 percent of our estimated proved reserves at year-end compared to 13 percent the previous year.

Apache has been the largest offshore held-by-production acreage owner since 2004 and is now the largest producer in waters less than 500 feet deep (shelf). The Devon acquisition and Mariner merger brought significant development and exploration opportunities with high-quality assets complementary to our existing assets, as well as a strategic presence in the deepwater Gulf of Mexico (waters greater than 500 feet deep). The deepwater Gulf of Mexico is relatively underexplored and oil prone and provides exposure to significant reserve and production

Table of Contents

potential. Acreage increased 76 percent to 5.3 million gross acres: 2.5 million deepwater, 1.4 million shelf, and 1.4 million onshore. Over 50 percent of the region s acreage was undeveloped.

In 2010 the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) announced a series of moratoria, which directed oil and gas lessees and operators to cease drilling new deepwater (depths greater than 500 feet) wells on the Outer Continental Shelf (OCS), and put oil and gas lessees and operators on notice that, with certain exceptions, the BOEMRE would not consider drilling permits for deepwater wells and related activities. While the moratoria have been formally lifted, no new permits for deepwater drilling have been issued as of the date of this filing.

In addition, the BOEMRE issued new regulations in 2010 requiring additional information, documentation and analysis for all new wells on the OCS. The effect of these new regulations was to significantly slow down issuance of permits for shallow wells. Apache continues to operate under these new regulations and, through February 2011, has received 25 drilling permits for shallow wells. Current permitting activity has been slowed compared to prior-year levels, and the Company has budgeted its exploration and development activity accordingly.

Despite the curtailment of activity in the region stemming from new regulations, the region had a productive year, drilling or participating in 63 wells (36 in the Gulf of Mexico), up from 26 wells (20 in the Gulf of Mexico) in 2009, and performing 365 workovers and recompletions.

As a result of 2010 acquisitions and the differing growth and opportunity profiles, we have divided the assets into three regions beginning in 2011: Gulf of Mexico shelf, Gulf of Mexico deepwater and Gulf Coast onshore. In 2011 the Company plans to invest approximately $200 million, $1 billion and $500 million in the Gulf Coast onshore, Gulf of Mexico shelf and Gulf of Mexico deepwater assets, respectively, subject to receipt of permits from BOEMRE. The capital will be spent on drilling, recompletion and development projects, equipment upgrades, production enhancement projects, lease acquisition, seismic acquisition and abandonment activities.

On September 16, 2010, the BOEMRE and the Department of the Interior issued a Notice to Lessees and Operators (NTL) updating the procedures and timing for decommissioning offshore wells and platforms. While the so called Idle Iron NTL may result in an acceleration of timing to abandon certain wells and remove certain platforms in the Gulf of Mexico, our ongoing active well and equipment abandonment program mitigated the impact of the new regulations on Apache. The Company spent approximately $260 million to plug offshore wells and remove platforms in 2010. With the addition of the Devon and Mariner offshore properties, we currently plan to spend approximately $350 million in 2011.

Central Region The Central region includes nearly 2,000 wells and controls over one million gross acres primarily in western Oklahoma, the Texas panhandle and east Texas. Most of the region s acreage is held-by-production. Although the reserves and production are primarily natural gas, given the price disparity between oil and gas, the region successfully targeted oil and liquids rich gas plays in 2010. Oil-and liquids-production increased by 54 percent and 90 percent, respectively, over the prior year. In 2010 Apache drilled or participated in the drilling of 84 wells, 99 percent of which were completed as producers. The region also performed 144 workovers and recompletions. The region s year-end estimated proved reserves, which were 90 percent natural gas, were six percent of Apache s total.

In the Anadarko basin, the Granite Wash play has long been a core stacked-pay target for the region, where we have drilled many vertical wells over the past several decades. As a result, we control approximately 200,000 gross acres in this liquid-rich play, mostly held-by-production. Despite the numerous vertical wells drilled, the Granite Wash is re-emerging as a horizontal play that is capitalizing on advances in horizontal drilling and fracturing technology and high oil prices given the rich liquids yield of the wells. In 2009 we drilled our first operated horizontal well in the Granite Wash. In 2010 we ramped up activity to 10 rigs, drilling 31 horizontal Granite Wash wells and testing six additional horizons including the Hogshooter interval, which is shallower, younger and oilier than previously tested Granite Wash targets. We have completed two wells in the Hogshooter interval, which are separated by over fifteen miles of what appears to be very prolific acreage, primarily owned and operated by Apache. We have identified hundreds of additional Granite Wash horizontal well locations across our acreage. In 2011 we plan to keep a minimum of eight rigs running in this play and drill in excess of 40 horizontal wells, targeting several horizons.

We have had success on the Anadarko shelf drilling relatively shallow horizontal wells into the Cherokee formation. In 2010 we completed four horizontal wells in the Cherokee play with vertical depths of 6,500 feet and horizontal penetrations of nearly one mile. These wells had average 30-day rates of 520 b/d and 850 Mcf/d and an average Apache working interest of 78 percent**.** The wells are currently producing an average of 150 b/d and 560 Mcf/d. We plan to drill 13 horizontal wells in the Cherokee in 2011. In addition, we have had success with our program targeting oil in Ochiltree County, Texas. During the year we drilled four wells in the Cleveland formation at a vertical depth of 7,500 feet and participated in one horizontal well in the Marmaton formation at a depth of 11,000 feet. Two of the Cleveland wells and the Marmaton well commenced production in late 2010 at an average initial rate of approximately 500 b/d. Apache s average working interest in the five wells is 90 percent. The two remaining Cleveland wells are awaiting completion, and we intend to keep at least one drilling rig running in the area throughout the year.

We are also employing horizontal drilling and multistage fracture technology in east Texas. In 2010 we drilled seven horizontal Bossier wells in Freestone County, Texas, where we own 45,000 gross acres. The wells produced an aggregate 7.34 Bcf during the year and are currently producing 37 MMcf/d, 33 MMcf/d net to Apache.

In 2011 the Central region plans to invest approximately $430 million in drilling, recompletions, equipment upgrades, production enhancement projects and lease acquisitions, primarily in the Anadarko basin. We currently plan to keep 12 rigs running all year, with more than 95 percent of the wells drilled horizontally and 89 percent of the wells drilled targeting oil or high liquid yield gas.

Permian Region Our Permian region, carved out of our Central region, grew significantly in 2010. In July we opened a new regional office in Midland. The region s property and acreage base increased substantially upon completion of the BP acquisition in July and the Mariner merger in November. These two transactions combined added approximately 35 Mboe/d of new production and more than doubled our acreage to over three million gross acres with exposure to every known play in the Permian Basin. The drilling rig count has increased from five operating at the beginning of 2010 to more than 20 at the end of the year. The workover and completion rig count has increased from 56 to 80, and the employee headcount in Midland and the field has increased by more than 200 during this same time period. The region drilled or participated in 263 wells and completed approximately 1,100 workovers and recompletions in 2010.

Apache is one of the largest operators in the Permian Basin, operating more than 11,000 wells in 152 fields, including 45 waterfloods and six CO_2 floods. Fourth-quarter net production was 59 Mb/d and 162 MMcf/d and included only six weeks of production from the properties acquired in the Mariner merger. The Permian region s year-end estimated proved reserves, which were 76 percent oil and liquids, were 25 percent of Apache s total.

During 2010 the Permian region tested horizontal drilling opportunities in four mature waterflood fields, the North McElroy, Shafter Lake, TXL South, and Dean Units, all of which resulted in commercial successes. The region ultimately drilled and completed a total of 17 horizontal wells in the units. The Midland team has developed a significant inventory of potential horizontal drilling applications on existing Apache acreage across the Permian Basin. In 2011 we plan to drill 41 horizontal wells across a number of the region s assets.

In 2010 the region signed a 20-year CO_2 supply contract to develop approximately 8.4 MMboe of estimated proved reserves at Roberts Unit. Our 2010 drilling results at Roberts Unit include 15 production and CO_2 injection wells that resulted in higher than predicted production rates. The CO_2 development at Roberts Unit will continue during 2011 with 43 new production and injection wells planned.

In 2011 the Permian Region plans to invest approximately $930 million in drilling, recompletion projects, equipment upgrades, expansion of existing facilities and equipment and leasing new acreage. We plan to keep more than 20 rigs running all year drilling an estimated 368 wells. The region s 2011 drilling activity will focus on a combination of Apache legacy assets and the newly acquired Mariner and BP properties. On the BP properties alone, the region has identified more than 2,000 drilling locations. Current plans include 130 wells in the Deadwood area (acquired from Mariner) where we hold 63,000 net acres subject to continuous drilling clauses and in the Empire Yeso area (acquired from BP), where we plan to drill approximately 55 wells.

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.

Table of Contents

Apache primarily markets its U.S. crude oil to integrated major oil companies, marketing and transportation companies and refiners. The objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices.

Canada

Overview Apache has 6.3 million net acres across the provinces of British Columbia, Alberta and Saskatchewan, including approximately 1.3 million net mineral and leasehold acres in Western Alberta and British Columbia acquired from BP in 2010. Our acreage base provides a significant inventory of both low-risk development drilling opportunities in and around a number of Apache fields and higher-risk, higher-reward exploration opportunities. At year-end 2010 our Canadian region held approximately 26 percent of our estimated proved reserves. In 2010 we drilled or participated in 182 wells in Canada, eight of which were exploratory wells. The region s 2010 natural gas production increased ten percent, while liquids production was one percent higher.

On our conventional assets, we are focused on oil projects located primarily in Alberta and Saskatchewan, enabling us to take advantage of the current strong oil prices. We will utilize our drilling technology and reservoir modeling expertise to identify and exploit unswept oil in our waterflood projects in the House Mountain, Leduc and Snipe Lake fields. Additional drilling for oil will continue on our enhanced oil recovery projects in Midale and Provost with long-term plans to develop and expand waterfloods and CO_2 projects. We will also continue intermediate-depth gas development drilling in Kaybob and West 5 areas.

Apache s near-term natural gas production growth will likely be driven by our activity in two large growth plays in British Colombia: shale gas in the Horn River basin and tight sands in the Noel area. In the Horn River basin, Apache has a 50-percent interest and 210,000 net acres. During 2010 Apache reached a peak of 100 MMcf/d net, drilled 29 new wells and completed 30 wells. In 2011 we plan to drill 10 and complete 28 wells in the Horn River basin. Apache acquired its 100-percent working interest in the Noel area from BP in October 2010. Gas production from Noel reached an exit rate of 100 MMcf/d in December 2010. In 2011 we are currently planning a horizontal drilling program of approximately 11 wells in the Noel Area. Apache has identified many years of drilling activity in both plays.

During the first quarter of 2010 Apache Canada Ltd. (Apache Canada), through its subsidiaries, purchased a 51 percent interest in a planned LNG export terminal (Kitimat LNG facility) and a 25.5-percent interest in a partnership that owns a related proposed pipeline. In the second quarter of 2010 EOG Resources Canada, Inc. (EOG Canada), through its wholly-owned subsidiaries, acquired the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the pipeline partnership from Pacific Northern Gas Ltd. (PNG). Under the terms of the agreement, PNG will operate and maintain the planned pipeline under a seven-year agreement with Apache Canada and EOG Canada with provisions for five-year renewals. It also includes a 20-year transportation service arrangement which may require Apache Canada and EOG Canada, under certain circumstances, to use a portion of PNG s current pipeline capacity. Upon close of the transaction, expected in the second quarter of 2011, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the pipeline partnership and proposed pipeline.

Apache Canada and EOG Canada plan to build the Kitimat LNG facility on Bish Cove near the Port of Kitimat, 400 miles north of Vancouver, British Columbia. The facility is planned for an initial minimum capacity of 700 MMcf/d, or five million metric tons of LNG per year, of which Apache Canada has reserved 51 percent. The proposed 287-mile pipeline will originate in Summit Lake, British Columbia, and is designed to link the Kitimat LNG facility to the pipeline system currently servicing western Canada s natural gas producing regions. Apache Canada will have rights to 51-percent of the capacity in the proposed pipeline. Completion of the front-end engineering and design (FEED) study and a final investment decision are targeted for late 2011. Construction is expected to commence in 2012, with commercial operations projected to begin in 2015.

Our plans for 2011 are to drill or participate in a total of 149 wells in Canada, including 129 development wells and 20 exploratory wells. The planned development includes nine drills and 28 completions in the Horn River basin.

During 2011 the region plans to invest approximately $800 million for drilling and development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately $25 million is allocated for Gathering, Transmission and Processing (GTP) assets.

Marketing Our Canadian natural gas marketing activities focus on sales to LDCs, 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 our firm transportation contracts to California, the Chicago area and eastern Canada. We sell the majority of our Canadian gas on a monthly basis at either first-of-the-month or daily prices. In 2010 approximately two percent of our gas sales were subject to long-term fixed-price contracts, with the latest expiration in 2011.

Our Canadian crude is sold primarily to integrated major oil companies and marketers. We sell our oil based on West Texas Intermediate (WTI) and sell our NGLs based on postings or a percentage of WTI. Prices are 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. We transport crude oil on 12 pipelines to the major trading hubs within Alberta and Saskatchewan, which enables us to achieve a higher netback for the production and to diversify our purchasers.

International

Apache s international assets are located in Egypt, Australia, offshore the U.K. in the North Sea, Argentina and Chile. In 2010 international assets contributed 52 percent of our production and 56 percent of our oil and gas production revenues. At year-end 30 percent of our estimated proved reserves were located outside North America.

Egypt

Overview Our commitment to Egypt began in 1994 with our first Qarun discovery well. Today we control 11.3 million gross acres making Apache the largest acreage holder in Egypt s Western Desert. Only 15 percent of our gross acreage in Egypt has been developed. That 15 percent produced an average of 189 Mb/d and 799 MMcf/d in 2010, 99 Mb/d and 375 MMcf/d net to Apache, which we believe makes Apache the largest producer of liquid hydrocarbons and natural gas in the Western Desert and the third largest in all of Egypt. The remaining 85 percent of our acreage is undeveloped, providing us with considerable exploration and development opportunities for the future. We have 3-D seismic covering over 12,000 square miles, or 68 percent of our acreage. In 2010 the region contributed 28 percent of our production revenue, 24 percent of our production and 10 percent of our year-end 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 24 separate concessions, under which the contractor partner pays all operating and capital expenditure costs for exploration and development. A percentage of the production, 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. In 2010, Apache retained approximately 52 percent and 47 percent, respectively, of the gross oil and gas produced from our Egyptian concessions. 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 10 to 25 years.

Apache s Egyptian operations had another year of growth in 2010: gross daily production increased 16 percent, and net daily production increased six percent. We maintained an active drilling and development program, drilling 204 wells, including 10 new field discoveries, and conducted 662 workovers and recompletions. In addition, we achieved a goal we set in 2005 to double gross equivalent production from our operated concessions by the end of 2010. In November we closed on the purchase of BP assets in Egypt s Western Desert, acquiring four development leases and one exploration concession as well as strategically-positioned infrastructure that will enable Apache to increase production from existing fields in the Western Desert.

Table of Contents

During 2011 the region plans to invest approximately $1.1 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Our drilling program includes a combination of development and exploration wells with current plans to drill 65 gross exploration wells, 50 percent more than 2010. We will also drill our first horizontal well in the Western Desert.

Egypt political unrest As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience in the Egyptian capital of Cairo that began on January 25, 2011, Egyptian president Hosni Mubarak stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces is now in power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and that the military would rule for six months until elections can be held. Following the advice of the U.S. State Department, Apache initially evacuated all non-essential personnel from Egypt. As conditions stabilized recently, approximately one-third of the evacuated employees returned. Apache s production, located in remote locations in the Western Desert, has continued uninterrupted; however, further changes 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 highly rated international insurers covering its investments in Egypt. In the aggregate, these policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache covering losses arising from confiscation, nationalization, and expropriation risks and 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 when actions taken by the Government of Egypt prevent Apache form exporting our share of production.

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, which corresponds to a Dated Brent price of $21.00 per barrel. Generally, this industry-pricing formula applies to all new gas discovered and produced. In exchange for extension of the Khalda Concession lease in July 2004, Apache agreed to accept the industry-pricing formula on a majority of gas sold, but retained the previous gas-price formula (without a price cap) until 2013 for up to 100 MMcf/d gross. This region averaged $3.62 per Mcf in 2010.

Oil from the Khalda Concession, the Qarun Concession and other nearby Western Desert blocks is sold primarily to third parties in the Mediterranean market or to EGPC when called upon to supply domestic demand. Oil sales are made either directly into the Egyptian oil pipeline grid, sold to non-governmental third parties including those supplying the Middle East Oil Refinery located in northern Egypt, or 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. In 2010 we sold 32 cargoes (approximately 10.1 MMbbls) of Western Desert crude oil into the export market from the El Hamra terminal located on the northern coast of Egypt. These export cargoes were sold to third parties at market prices above our domestic prices received from EGPC. Additionally, Apache sold Qarun oil (approximately 10.7 MMbbls) at the Sidi Kerir terminal, also located on the northern coast of Egypt. This Qarun oil was sold at prevailing market prices into the domestic market to non-governmental purchasers (1.3 MMbbls) or exported primarily to refiners in the Mediterranean region (15 cargoes for approximately 9.4 MMbbls).

Australia

Overview Apache s holdings in Australia are focused offshore Western Australia in the Carnarvon basin, where we have operated since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993, the Exmouth basin and the Browse basin. We also have exploration acreage in the Gippsland basin offshore southeastern Australia. Production operations are concentrated in the Carnarvon and Exmouth basins. In total, we control approximately 12.2 million gross acres in Australia through 35 exploration permits, 14 production licenses and six retention leases. In addition, we have one production license and four retention leases pending confirmation.

During the year the region participated in drilling 31 wells, of which 23 were productive. In addition, we expanded our exploration opportunities in the Carnarvon and Exmouth basins via farm-ins to seven permits. The transactions resulted in a 58-percent increase in our net undeveloped acreage in the Carnarvon basin and added 1.9 million net acres for exploration in the Exmouth basin. Oil production increased by 369 percent on initial production from the development of our 2007 Van Gogh and Pyrenees oil field discoveries, while gas production increased by nine percent. Production from Australia accounted for approximately 12 percent of our total 2010 production, and year-end estimated proved reserves were 11 percent of Apache s total.

The region has a pipeline of projects that are expected to contribute to production growth as they are brought on-stream over coming years.

In 2011, development of our Reindeer field discovery should be complete with first production expected late in the year upon completion of our Devil Creek Gas Plant. The plant will be Western Australia s third domestic natural gas processing hub and the first new one in more than 15 years. The two-train plant is designed to process 200 million cubic feet of gas per day from the Apache-operated Reindeer field. In 2009, we entered into a gas sales contract covering a portion of the field s future production. Under the contract, Apache and its joint venture partner agreed to supply 154 Bcf of gas over seven years (approximately 60 MMcf/d beginning in the fourth quarter of 2011) at prices substantially higher than we have historically received in Western Australia. Apache owns a 55-percent interest in the field. Also in 2011, initial production is projected from the Halyard-1 discovery well which is a subsea completion tied back to the existing gas facilities on Varanus Island.

In 2012, the 2010 Spar-2 discovery is projected to commence production through an extension of the Halyard sub sea infrastructure which will also allow for the tie-in of future wells.

In 2013, first production is projected from four gas wells completed in 2010 in the Macedon gas field. We have a 28 percent non-operating working interest in the field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant to be built at Ashburton North in Western Australia. The project, approved in 2010, is currently underway; with first production projected in 2013.

Also in 2013 first production is projected from the Coniston oil field which lies just north of the Van Gogh field. The project was sanctioned for development in 2010. Current plans call for the field to be produced from subsea completions tied back to the Van Gogh field floating, production, storage and offloading (FPSO) Ningaloo Vision.

In 2014 first production from the Balnaves field is projected, should the project proceed past Final Investment Decision (FID) stage. The Balnaves field is an oil accumulation in the Brunello gas field, where Apache drilled three successful development wells which we plan to produce through a FPSO. The project is currently in the Front End FEED stage with FID currently projected for the second half of 2011.

In 2016 we are projecting to begin production from our operated Julimar and Brunello field gas discoveries through the Chevron operated Wheatstone LNG hub, in which we own a foundation equity partner interest of 13 percent. Apache s projected net gas sales from the fields are 160 MMcf/d and 3,250 b/d with a projected 15-year production plateau when the multi-year project is fully operational. The project, which is currently in FEED, will convert the gas into LNG for sale on the world market. World LNG prices are typically oil-linked prices and are currently higher than the historical gas prices in Western Australia. The project FID is scheduled for 2011, with first LNG projected in 2016.

During 2011 the region plans to invest approximately $1.2 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately half of the 2011 investment will be for development and processing facilities in connection with the projects discussed above.

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 escalation clauses based on either the Australian consumer price index or a commodity linkage. As of

December 31, 2010, Apache had a total of 18 active gas contracts in Australia with expiration dates ranging from November 2012 to July 2030. Recent increases in demand and higher development costs have increased the supply prices required from the local market in order to support the development of new supplies. As a result, market prices received on recent contracts, including our Reindeer field, are substantially higher than historical levels.

We anticipate selling LNG from our Julimar and Brunello field gas discoveries at prices tied to oil and sold into international markets.

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 a premium, which are typically above NYMEX oil prices.

North Sea

Overview Apache entered the North Sea in 2003 after acquiring an approximate 97-percent working interest in the Forties field (Forties). In 2010 the North Sea region produced 20.9 MMboe (99 percent oil), approximately nine percent of our total worldwide production and 13 percent of Apache s oil and gas production revenues. During 2010 production from Forties decreased seven percent compared to 2009 as natural well decline and unplanned maintenance downtime exceeded gains from drilling. At year-end 2010, Apache had total estimated proved reserves of 155 MMbbls of crude oil in this region, approximately five percent of our year-end estimated proved reserves. Apache acquired Forties with 45 producing wells. Today, there are 77 producing wells with an inventory of future locations. By the end of the first quarter of 2010, Apache had produced and sold, net to its interest, oil volumes in excess of the proved reserves booked when we acquired this interest in 2003.

During the summer of 2010 a new 3-D seismic survey was acquired in Forties. Comparison of this data with 3-D seismic shot in prior years has highlighted many areas of bypassed oil in the reservoir and provided better definition of existing targets. In 2010, 20 wells were drilled into the Forties reservoir, of which 12 were productive. We project that this Forties success rate of 60 percent will increase in the future, as drilling results from late December 2010 and early January 2011 have validated the new 4-D evaluation and geological interpretation. We also drilled three exploration wells and one development well outside Forties. The development well and one of the exploration wells were successful.

In 2011 the region will invest approximately $850 million on a diverse set of capital projects. Forties will see another year of active drilling with two platform rigs and a jack-up in operation. Construction of the Forties Alpha Satellite Platform is underway and is projected to be complete by mid-year 2012. This platform will sit adjacent to the main Alpha Platform and provide an additional 18 drilling slots along with power generation, fluid separation, gas lift compression and oil export pumping. Also, during the third quarter of 2011 drilling will commence on the Bacchus field, Apache s first North Sea subsea field development. First production is projected by year-end of 2011. The region also expects to participate in at least two exploration wells outside Forties.

In January 2011 a subsea pipeline connecting our Forties Bravo platform to our Charlie platform was shut-in because of corrosion. A project is underway to re-route the production through a smaller line until a new flexible pipeline is installed. This intermediate solution should be completed by the first of March 2011 and will allow us to produce approximately half of the 11,600 b/d that flowed through the main pipeline. The new main subsea pipeline will be completed by September 2011.

Marketing In 2010 we sold our Forties crude under both term contracts (70 percent) and spot cargoes (30 percent). The term sales are composed of a market-based index 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.

All 2011 production will be sold under a term contract with a per-barrel premium to the Dated Brent index. A separate physical sales contract within the term sale for 20,000 b/d was entered into with a floor price of $70.00 per barrel and an average ceiling price of $98.56 per barrel. This contract will be settled against Dated Brent.

Table of Contents

Argentina

Overview We have had a continuous presence in Argentina since 2001, which was expanded substantially by two acquisitions in 2006. We currently have operations in the Provinces of Neuquén, Rio Negro, Tierra del Fuego and Mendoza. We have interests in 24 concessions, exploration permits and other interests totaling over 3.4 million gross acres (2.9 million net). Apache now holds oil and gas assets in three of the main Argentine hydrocarbon basins: Neuquén, Austral and Cuyo. Our concessions have varying expiration dates ranging from four years to over fifteen years remaining, subject to potential additional extensions. In 2010 Argentina produced seven percent of our worldwide production and held four percent of our estimated proved reserves at year-end.

In 2010 the region had its most successful development drilling program in its history, drilling 56 gross wells:; 43 in the Neuquén basin and 13 in the Austral basin of Tierra del Fuego. Drilling focused on shallow development targets, 93 percent of the wells were successful. In addition, the region completed 106 capital projects consisting of recompletions, increasing lifting capacity, and facility projects.

Also during 2010 Apache acquired approximately 567 square kilometers of 3-D seismic on two blocks located in the Cuyo basin. Apache employed new cable-less technology intended to minimize environmental impact in the area, the first time this technology has been used in Argentina. We are currently analyzing the results from the seismic shoot and expect to commence a drilling campaign in the Cuyo basin in the first quarter of 2011.

In 2011 we will begin negotiations for extensions of three concessions each in the Tierra del Fuego and Rio Negro Provinces, which are scheduled to expire in 2016 and 2017. Future investment by Apache in the Tierra del Fuego Province will be significantly influenced by the probability of obtaining the Province s agreement to an extension of the present concession expirations. In March 2009 Apache reached an agreement with the Province of Neuquén to extend eight federal oil and gas concessions for 10 additional years. The concessions, which were scheduled to expire between 2015 and 2017, encompass approximately 590,000 net acres, including exploratory areas totaling 514,000 net acres. Neuquén operations generate about half of Apache s total output in Argentina.

During 2011 the region plans to invest approximately $300 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

Marketing

Natural Gas Apache sells its natural gas through three avenues:

> Gas Plus program: This program was instituted by the Argentine government to encourage new gas supplies through the development of tight sands and unconventional reserves. Under this program, qualifying projects are allowed to sell gas at prices that are above the regulated rates. During 2010 Apache signed three Gas Plus contracts totaling 63 MMcf/d of gross production from fields in the Neuquén and Rio Negro Provinces. The first contract, for 10 MMcf/d at $4.10 per MMBtu for 2010, has been extended through 2011 for 11 MMcf/d at the $4.10 per MMBtu. The other two contracts, which together totaled 53 MMcf/d at $5.00 per MMBtu, are expected to commence in the first quarter of 2011. The gas supply is required to come from wells drilled in the projects approved fields and formations. We believe this program, reflects changing market conditions, which point to improving markets and price realizations going forward.
>
> Government-regulated pricing: The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. During 2010 we realized an average price of $1.20 per Mcf on government-regulated sales.

Unregulated market: The majority of our remaining volumes are sold into the unregulated market. In 2010 realizations averaged $2.65 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. In Tierra del Fuego, similar pricing formulas exist; however, Apache retains the value-added tax collected from buyers, effectively increasing realized prices by 21 percent. As a result, 2010 oil prices realized from Tierra del

Table of Contents

Fuego oil production averaged $65.03 per barrel as compared to our Neuquén basin production, which averaged $53.68 per barrel.

Chile

In November 2007 Apache was awarded exploration rights on two blocks comprising approximately one million net acres on the Chilean side of Tierra del Fuego. This acreage is adjacent to our 552,000 net acres on the Argentine side of the island of Tierra del Fuego and represents a natural extension of our expanding exploration and production operations. The Lenga and Rusfin Blocks were ratified by the Chilean government on July 24, 2008. In January 2009 a 3-D seismic survey totaling 1,000 square kilometers was completed, and in November 2009 the first of a three-well exploration program commenced drilling. The three wells have now been drilled, and we are currently evaluating results.

Major Customers

In 2010 purchases by Shell accounted for 15 percent of the Company s worldwide oil and gas production revenues.

Drilling Statistics

Worldwide in 2010 we participated in drilling 904 gross wells, with 826 (91 percent) completed as producers. We also performed nearly 2,500 workovers and recompletions during the year. 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 exploitation wells. In addition to our completed wells, at year-end several wells had not yet reached completion: 51 in the U.S. (25.04 net); 7 in Canada (6.18 net); 22 in Egypt (20 net); 2 in Australia (0.64 net); 3 in the North Sea (2.91 net); and 7 in Argentina (5.15 net).

Table of Contents

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
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
2009									
United States	5.6	2.5	8.1	107.6	8.5	116.1	113.2	11.0	124.2
Canada	3.0		3.0	136.8	12.8	149.6	139.8	12.8	152.6
Egypt	8.6	10.4	19.0	126.4	4.0	130.4	135.0	14.4	149.4
Australia	6.9	3.8	10.7	4.7		4.7	11.6	3.8	15.4
North Sea	1.0		1.0	12.6	2.9	15.5	13.6	2.9	16.5
Argentina	3.4	0.7	4.1	25.5		25.5	28.9	0.7	29.6
Other International	2.0		2.0				2.0		2.0
Total	30.5	17.4	47.9	413.6	28.2	441.8	444.1	45.6	489.7
2008									
United States	4.5	6.6	11.1	334.8	25.3	360.1	339.3	31.9	371.2
Canada	3.9	5.0	8.9	328.0	10.1	338.1	331.9	15.1	347.0
Egypt	18.7	11.5	30.2	193.2	5.8	199.0	211.9	17.3	229.2
Australia	6.4	9.0	15.4	12.5		12.5	18.9	9.0	27.9
North Sea				11.7		11.7	11.7		11.7
Argentina	7.5	2.0	9.5	54.4	6.2	60.6	61.9	8.2	70.1
Total	41.0	34.1	75.1	934.6	47.4	982.0	975.6	81.5	1,057.1

Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of December 31, 2010, is set forth below:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	5,165	3,040	2,370	7,995	17,535	11,035

Canada	10,100	8,405	2,500	1,100	12,600	9,505
Egypt	52	51	722	694	774	745
Australia	22	9	20	12	42	21
North Sea			77	75	77	75
Argentina	425	390	520	445	945	835
Total	15,764	11,895	16,209	10,321	31,973	22,216

Gross natural gas and crude oil wells include 1,600 wells with multiple completions.

Table of Contents

Production, Pricing and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGLs and gas production, 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:

Year Ended December 31,	Production Oil (MMbbls)	Production NGLs (MMbbls)	Production Gas (Bcf)	Average Lease Operatinge Cost per Boe	Average Sales Price Oil (Per bbl)	Average Sales Price NGLs (Per bbl)	Average Sales Price Gas (Per Mcf)
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	69.75	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
2009							
United States	32.5	2.2	243.1	$ 10.59	$ 59.06	$ 33.02	4.34
Canada	5.5	0.8	131.1	11.46	56.16	25.54	4.17
Egypt	33.6		132.3	5.17	61.34		3.70
Australia	3.6		67.0	6.84	64.42		1.99
North Sea	22.3		1.0	8.19	60.91		13.15
Argentina	4.2	1.2	67.4	6.78	49.42	18.76	1.96
Total	101.7	4.2	641.9	8.48	59.85	27.63	3.69
2008							
United States	32.9	2.2	248.8	$ 12.62	$ 83.70	$ 58.62	$ 8.86
Canada	6.3	0.7	129.1	14.00	93.53	49.33	7.94
Egypt	24.4		96.5	6.47	91.37		5.25
Australia	3.0		45.0	9.85	91.78		2.10
North Sea	21.8		1.0	10.00	95.76		18.78
Argentina	4.5	1.1	71.6	6.58	49.46	37.83	1.61
Total	92.9	4.0	592.0	10.56	87.80	51.38	6.70

Gross and Net Undeveloped and Developed Acreage

The following table sets out our gross and net acreage position in each country where we have operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
United States	4,809,425	2,846,337	4,955,265	2,848,363
Canada	3,834,513	2,960,531	4,527,542	3,334,602
Egypt	9,572,015	6,192,027	1,741,102	1,624,780
Australia	11,456,850	6,587,180	744,900	402,500
North Sea	780,811	406,157	41,019	39,846
Argentina	3,149,882	2,701,182	220,840	188,226
Chile	1,205,403	1,036,626		
Total	34,808,899	22,730,730	12,230,668	8,438,317

Table of Contents

As of December 31, 2010, we had 3,284,814, 1,588,390, and 3,552,045 net acres scheduled to expire by December 31, 2011, 2012, and 2013, respectively, if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licenses and concession areas through operational or administrative actions and do not project a significant portion of our net acreage position to expire before such actions occur.

As of December 31, 2010, 30 percent of U.S. net undeveloped acreage and 36 percent of Canadian undeveloped acreage was held by production.

Estimated Proved Reserves and Future Net Cash Flows

Effective December 31, 2009, Apache adopted revised oil and gas disclosure requirements set forth by the SEC in Release No. 33-8995, Modernization of Oil and Gas Reporting and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Topic 932, Extractive Industries Oil and Gas. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGL s 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. 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. Reserve estimates are considered proved if they are economically producible and are supported by either actual production or conclusive formation tests. 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 which 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. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

PUD 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.

Table of Contents

The following table shows proved oil, NGL and gas reserves as of December 31, 2010, based on average commodity prices in effect on the first day of each month in 2010, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. The 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	423	92	2,284	895
Canada	90	24	2,182	478
Egypt	110		748	234
Australia	48		683	162
North Sea	116		4	116
Argentina	16	6	462	100
Proved Undeveloped:				
United States	214	30	989	409
Canada	57	4	1,310	280
Egypt	17		329	72
Australia	18		805	152
North Sea	39			39
Argentina	4	1	71	16
TOTAL PROVED	1,152	157	9,867	2,953

As of December 31, 2010, Apache had total estimated proved reserves of 1,309 MMbbls of crude oil, condensate and NGLs and 9.9 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 3.0 billion barrels of oil or 17.7 Tcf of natural gas, of which oil represents 39 percent. As of December 31, 2010, the Company s proved developed reserves totaled 1,985 MMboe and estimated PUD reserves totaled 968 MMboe, or approximately 33 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 proved undeveloped reserves as of December 31, 2010, 2009, 2008 and 2007, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 12 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, 2010, 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 month in 2010 and 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. Future net cash flows as of December 31, 2008, were estimated using commodity prices in effect at the end of that year, in accordance with the SEC guidelines in effect prior to the issuance of the Modernization Rules.

Proved Undeveloped Reserves

The Company s total estimated PUD reserves of 968 MMboe as of December 31, 2010, increased by 237 MMboe over the 731 MMboe of PUD reserves estimated at the end of 2009. This increase was, in part, due to our 2010 acquisitions described above. During the year, Apache converted 64 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America we converted 31 MMboe, with the remaining 33 MMboe in our international areas.

During the year a total of approximately $1.1 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2009. 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 $517 million on PUD reserve development activity in North America and $574 million in the international areas. At year-end 2010, no material amounts of PUD reserves remain undeveloped for five years or more after they were initially disclosed as PUD reserves.

Table of Contents

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 centralized 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 2010 the properties selected for each country ranged from 63 to 100 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 85 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 63 percent of total proved reserves; 72 percent of proved developed reserves and 45 percent of proved undeveloped reserves. Properties with proved undeveloped reserves generally have an associated capital expenditure required to develop those reserves included in their net present value calculation, reducing their value relative to proved developed reserves. For this reason those properties are less likely to be selected for the audit, resulting in a higher percentage of proved developed reserves selected for review.

During 2010, 2009, and 2008, Ryder Scott s review covered 72, 79 and 82 percent of the Company s worldwide estimated proved reserves value and 63, 69, and 73 percent of the Company s total proved reserves, respectively. 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 United Kingdom s total proved reserves. Ryder Scott s review of 2009 covered 66 percent of U.S., 48 percent of Canada, 63 percent of Argentina, 96 percent of Australia, 86 percent of Egypt and 80 percent of the United Kingdom s total proved reserves. Ryder Scott s review of 2008 covered 70 percent of U.S., 51 percent of Canada, 58 percent of Argentina, 100 percent of Australia, 87 percent of Egypt and 89 percent of the United Kingdom 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.

Table of Contents

Employees

On December 31, 2010, we had 4,449 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 2010 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. The current lease on our principal executive offices runs through December 31, 2013. For information regarding the Company s obligations under its office leases, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Contractual Obligations and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Title to Interests

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

Additional Information about Apache

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

Remediation Plans and Procedures

Apache adopted a Region Spill Response Plan (the Plan) for its Gulf of Mexico operations to ensure a rapid and effective response to spill events that may occur on Apache-operated properties. Periodically, drills are conducted to measure and maintain the effectiveness of the Plan. These drills include the participation of spill response contractors, representatives of the Clean Gulf Associates (CGA, described below), and representatives of governmental agencies. The primary association available to Apache in the event of a spill is CGA. Apache has received approval for the Plan from the BOEMRE. Apache personnel review the Plan annually and update where necessary.

Apache is a member of, and has an employee representative on the executive committee of, CGA, a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico. CGA was created to provide a means of effectively staging response equipment and providing immediate spill response for its member companies operations in the Gulf of Mexico. To this end, CGA has bareboat chartered (an arrangement for the hiring of a boat with no crew or provisions included) its marine equipment to 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. MSRC maintains CGA s equipment (currently including 13 shallow water skimmers, four fast response vessels with skimming capabilities, nine fast response containment-skimming units, a large skimming containment barge, numerous containment systems, wildlife cleaning and rehabilitation facilities and dispersant inventory) at various staging points around the Gulf of Mexico in its ready state, and in the event of a spill, MSRC stands ready to mobilize all of this equipment to CGA members. MSRC also handles the maintenance and mobilization of CGA non-marine equipment. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies. In 2010 we paid CGA approximately $312,000: $12,800 per capita and a fee based on 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, which entitles any Apache entity worldwide to access their service. Oil Spill Response Limited has access to resources from the Global Response Network, a collaboration of seven major oil industry funded spill response organizations worldwide. Oil Spill Response Limited 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, Oil Spill Response Limited s resources may be, and have been, deployed to areas across the globe, such as the Gulf of Mexico. In addition, resources of other organizations are available to Apache as a non-member, such as those of MSRC and National Response Corporation (NRC), albeit at a higher cost. MSRC has an extensive inventory of oil spill response equipment, independent of and in addition to CGA s equipment, currently including 19 oil spill response barges with storage capacities between 12,000 and 68,000 barrels, 68 shallow water barges, over 240 skimming systems, six self-propelled skimming vessels, seven mobile communication suites with internet and telephone connections, as well as marine and aviation communication capabilities, various small crafts and shallow water vessels and dispersant aircraft. MSRC has contracts in place with many 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 work boats, 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 these companies changes from time-to-time and current information is generally available on each of the companies websites.

Apache 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. In 2011, Apache s wholly-owned subsidiary Apache Deepwater LLC, retained the Helix Energy Solution Group in conjunction with its CGA membership, and will become a member of the Marine Well Containment Company to fulfill the government permit requirements for containment and oil spill response plans in Deepwater operations.

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 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, 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. In November 2010 Apache entered into an agreed order with the Texas Commission on Environmental Quality and paid a total of $111,000 in administrative penalties to settle allegations regarding operations of two natural gas processing plants.

Changes to existing, or additions of, laws, regulations, enforcement policies or requirements in one or more of the countries or regions in which we operate could require us to make additional capital expenditures. While the events in the U.S. Gulf of Mexico in 2010 have resulted in the enactment of, and may result in the enactment of additional, laws or requirements regulating the discharge of materials into the environment, we do not believe that any such regulations or laws enacted or adopted as of this date will have a material adverse impact on our cost of operations, 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. There are likely to be significant long-term effects resulting from the recession and credit market crisis, 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 a sustainable, yet lower, 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.

In addition, the Organisation for Economic Co-operation and Development (OECD) has encouraged countries with large federal budget deficits to initiate deficit reduction measures. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand.

Table of Contents

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 2010 ranged from a high of $92.89 per barrel to a low of $68.01 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2010 ranged from a high of $6.01 per MMBtu to a low of $3.29 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 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.

We recorded asset impairment charges during 2008 and 2009. No impairment charges were recorded during 2010. If commodity prices decline, there could be additional impairments of our oil and gas assets or other investments or an impairment 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 flow.

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, 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:

- drilling well blowouts, explosions and cratering;
- pipeline ruptures and spills;
- fires;
- formations with abnormal pressures;
- equipment malfunctions; and
- 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.

Failure or loss of equipment, as the result of equipment malfunctions 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, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture 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 flow and, in turn, our results of operations could be materially and adversely affected.

The Devon and Mariner transactions have increased our exposure to Gulf of Mexico operations.

Our recent acquisitions of oil and gas assets in offshore Gulf of Mexico from Devon Energy Corporation and Mariner Energy, Inc. have increased our exposure to offshore Gulf of Mexico operations. Greater offshore concentration proportionately increases risks from delays or higher costs common to offshore activity, including severe weather, availability of specialized equipment and compliance with environmental and other laws and regulations.

In addition, as a result of the current lack of drilling activity in the deepwater Gulf of Mexico and slowdown of drilling activity on the Gulf of Mexico shelf caused by the regulatory response to the Deepwater Horizon incident, drilling equipment and oil field services companies may decide to exit the Gulf of Mexico, making such services less available and/or more expensive once drilling activities are allowed to fully resume.

Any 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.

As has been widely reported, on April 20, 2010, a fire and explosion occurred onboard the semisubmersible drilling rig Deepwater Horizon, which lead to a significant oil spill that affected the Gulf of Mexico. In response to this incident, the BOEMRE ceased issuing drilling permits pursuant to a series of moratoria, and all deepwater drilling activities in progress were suspended. Although the moratoria have been lifted, the DOI has not issued any permits related to the drilling of new exploratory wells in the deepwater Gulf of Mexico as of January 31, 2011. In 2010 the DOI issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability.

In January 2011 the President s National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps. The European Commission has recommended that new legislation be enacted to enhance the safety of offshore oil and gas activities. Additional legislation or regulation is being discussed which could require companies operating in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility, a certificate required by the Oil Pollution Act of 1990 which evidences a company s financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual insurance fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

The BOEMRE is expected to continue to issue new safety and environmental guidelines or regulations for drilling in the Gulf of Mexico, and other regulatory agencies could potentially issue new safety and environmental guidelines or regulations in other geographic regions, and may take other steps that could increase the costs of exploration and production, reduce the area of operations and result in permitting delays. We are monitoring legislation and regulatory developments; however, it is difficult to predict the ultimate impact of any new guidelines, regulations or legislation. A prolonged suspension of drilling activity in the U.S. and abroad and new regulations 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 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.

During 2010 credit markets recovered but 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 whose completion 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 Mariner and BP transactions have exposed us to additional risks and uncertainties with respect to the acquired businesses and their operations.

Although the acquired Mariner and BP businesses are generally subject to risks similar to those to which we are subject in our existing businesses, the Mariner and BP transactions may increase these risks. For example, the increase in the scale of our operations may increase our operational risks. The publicity associated with the oil spill in the Gulf of Mexico resulting from the fire and explosion onboard the Deepwater Horizon, which was under contract to BP, may cause regulatory agencies to scrutinize our operations more closely. This additional scrutiny may adversely affect our operations.

We may have difficulty combining the operations of both Mariner and the BP properties, and the anticipated benefits of these transactions may not be achieved.

Achieving the anticipated benefits of the Mariner and BP transactions will depend in part upon whether we can successfully integrate the operations of Mariner and the BP properties with ours. Our ability to integrate the operations of Mariner and the BP properties successfully will depend on our ability to monitor operations, coordinate exploration and development activities, control costs, attract, retain and assimilate qualified personnel and maintain compliance with regulatory requirements. The difficulties of integrating the operations of Mariner and the BP properties may be increased by the necessity of combining organizations with distinct cultures and widely dispersed operations. The integration of operations following these transactions will require the dedication of management and other personnel, which may distract their attention from the day-to-day business of the combined enterprise and prevent us from realizing benefits from other opportunities. Completing the integration process may be more expensive than anticipated, and we cannot assure you that we will be able to effect the integration of these operations smoothly or efficiently or that the anticipated benefits of the transactions will be achieved.

Several significant matters in the BP Acquisition were not resolved before closing.

Because of the relatively short time period between signing the BP Purchase Agreements and the closing of the acquisition of the BP properties, several significant matters commonly resolved prior to closing such an acquisition have been reserved for after closing. We did not have sufficient time before closing on the BP Properties to conduct a full title review and environmental assessment. Although remedies are limited for title, we may discover adverse environmental or other conditions after closing and after the time periods specified in the BP Purchase Agreements during which we may be able to seek, in certain cases, indemnification from or cure of the defect or adverse condition by BP for such matters. For example, Apache Canada Ltd. has asserted a claim against BP Canada arising from the acquisition of certain Canadian properties under the BP Purchase Agreements. The dispute centers on Apache Canada Ltd. s identification of Alleged Adverse Conditions, as that term is defined in the BP Purchase Agreements, and more specifically, the contention that liabilities associated with such conditions were retained by BP Canada as seller. There can be no assurance that we will prevail on this or any future claim against BP.

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 BP Purchase Agreements 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.

Table of Contents

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, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. In accordance with the SEC s revisions to rules for oil and gas reserves reporting, which we adopted effective December 31, 2009, 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. The estimates 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 assumed effects of regulations by governmental agencies, including the impact of the SEC s new oil and gas company reserves reporting requirements;
- future operating costs;
- severance and excise taxes;
- development costs; 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 based on risk of recovery 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.

Table of Contents

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.

Legislation is pending in a number of countries where Apache operates including Australia, and Canada, the United Kingdom, that, if enacted, could tax or assess some form of greenhouse gas (GHG) related fees on Company operations and could lead to increased operating expenses. Such legislation, if enacted, could also potentially cause the Company to make significant capital investments for infrastructure modifications. Through 2011, three of the jurisdictions in which the Company has operations, Alberta and British Columbia, Canada and the United Kingdom (European Union), have enacted legislation which exposes the Company to financial payments related to GHG emissions from production facilities. This exposure has not been material to date.

Furthermore, various governmental entities in countries where Apache operates have discussed regulatory initiatives that could, if adopted, require the Company to modify existing or planned infrastructure to meet GHG emissions performance standards and necessitate significant capital expenditures. At some level, the cost of performance standards may force the early retirement of smaller production facilities, which in aggregate may have a material adverse effect on Apache s business.

Several of the countries we operate in are signatories to current international accords related to climate change, such as the Kyoto Protocol to the United Nations Framework Convention on Climate Change. Given the current implementation of the Kyoto Protocol, we do not expect it to have a material impact on the Company.

Several indirect consequences of regulation and business trends have potential to impact us. Taxes or fees on carbon emissions could lead to decreased demand for fossil fuels. Consumers may prefer alternative products and unknown technological innovations may make oil and gas less significant energy sources.

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 2012 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 14, 2011, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2012. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The 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.

Proposed federal 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 the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. 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 well-bore. 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 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 2010 our operations in Egypt contributed 28 percent of our production revenue, 25 percent of total production and 10 percent of total estimated proved reserves. In 2010 we sold all of our Egyptian gas production and 34 percent of our Egyptian oil production to the Egyptian General Petroleum Company (EGPC), the Egyptian state-owned oil company, and sold the remainder in the export market. As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience that began on January 25, 2011, in the Egyptian capital of Cairo, former Egyptian president Hosni Mubarak has stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces is now in power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and that the military would rule for six months until elections can be held. Further changes 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.

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 52 percent of our 2010 production was outside North America and approximately 30 percent of our estimated proved oil and gas reserves on December 31, 2010 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 recent weeks civil unrest, which started in Tunisia, has spread to the Middle East. Prolonged and/or widespread regional conflict in the Middle East could have the following results, among others:

- volatility in the 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;

- lack of availability of drilling rigs, oil field 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, are affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect our results of operation, 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 result 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 SEC STAFF COMMENTS*

As of December 31, 2010, 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. *[REMOVED AND RESERVED]*

PART II

ITEM 5. *MARKET FOR THE REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

During 2010 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 2010 and 2009. 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.

	2010				2009			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 108.92	$ 95.15	$ .15	$ .15	$ 88.07	$ 51.03	$ .15	$ .15
Second Quarter	111.00	83.55	.15	.15	87.04	61.60	.15	.15
Third Quarter	99.09	81.94	.15	.15	95.77	65.02	.15	.15
Fourth Quarter	120.80	96.51	.15	.15	106.46	88.06	.15	.15

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2011 (last trading day of the month), was $119.36 per share. As of January 31, 2011, there were 382,752,217 shares of our common stock outstanding held by approximately 5,700 stockholders of record and approximately 440,000 beneficial owners.

We have paid cash dividends on our common stock for 46 consecutive years through December 31, 2010. 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 7 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 2010 annual meeting of stockholders, which is incorporated herein by reference.

Table of Contents

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, 2005, through December 31, 2010.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Apache Corporation, S&P 500 Index
and the Dow Jones US Exploration & Production Index

	2005	2006	2007	2008	2009	2010
Apache Corporation	$ 100.00	$ 97.70	$ 159.16	$ 111.05	$ 154.93	$ 180.12
S & P s Composite 500 Stock Index	100.00	115.79	122.16	76.96	97.33	111.99
DJ US Expl& Prod Index	100.00	105.37	151.39	90.65	127.42	148.14

* $100 invested on 12/31/05 in stock including reinvestment of dividends.
Fiscal year ending December 31.

Table of Contents

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, 2010, 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, the 2009 numbers in the following table reflect a $2.82 billion ($1.98 billion net of tax) non-cash write-down of the carrying value of the Company s U.S. and Canadian proved oil and gas properties as of March 31, 2009, as a result of ceiling test limitations. 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,				
	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Income Statement Data					
Total revenues	$ 12,092	$ 8,615	$ 12,390	$ 9,999	$ 8,309
Income (loss) attributable to common stock	3,000	(292)	706	2,807	2,547
Net income (loss) per common share:					
Basic	8.53	(.87)	2.11	8.45	7.72
Diluted	8.46	(.87)	2.09	8.39	7.64
Cash dividends declared per common share	.60	.60	.70	.60	.50
Balance Sheet Data					
Total assets	$ 43,425	$ 28,186	$ 29,186	$ 28,635	$ 24,308
Long-term debt	8,095	4,950	4,809	4,012	2,020
Shareholders equity	24,377	15,779	16,509	15,378	13,191
Common shares outstanding	382	336	335	333	331

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

Table of Contents

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 seven countries: the U.S., Egypt, Australia, offshore the U.K. in the North Sea (North Sea), Argentina and Chile.

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. Apache s long-term perspective has many dimensions, with the following core strategic components:

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

A cornerstone of our strategy is balancing our portfolio through diversity of geologic risk, geographic risk, hydrocarbon mix (crude oil versus natural gas) and reserve life in order to achieve consistency in results. Our portfolio of geographic locations provides variation of all of these factors and, additionally, in the case of Australia and Argentina, the potential for increasing the value of our investments through rising natural gas prices. By maintaining a balanced hydrocarbon mix, we are protecting against price deterioration in a given product while retaining upside potential through a significant increase in either commodity price. For example, in 2010 oil and liquids provided 52 percent of our production but 77 percent of our total oil and gas revenues. We were well positioned to realize the benefit of higher oil prices, enabling record financial results despite North America natural gas prices that were under pressure most of the year.

Each operating region has a significant producing asset base as well as large undeveloped acreage positions which provide room 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 budgets accordingly. We review capital allocations, at least quarterly, through a disciplined and focused process of reviewing internally-generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects or, occasionally, new core areas which could enhance our portfolio. In addition, we actively seek to identify and pursue ways to maintain efficient levels of costs and expenses. Our overall approach to managing cash expenditures has enabled us to consistently deliver strong results with 2010 return on average capital employed and return on equity of 12 percent and 15 percent, respectively.

Preserving financial flexibility is also important to our overall business philosophy. We ended 2010 with a year-end debt-to-capitalization ratio of 25 percent, an increase of only one percent from the prior year despite current-year capital investments of $17 billion, including acquisitions totaling more than $11 billion.

Throughout the cycles of our industry, these strategic principles have underpinned our ability to deliver production, reserve growth and competitive investment rates of return 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

While Apache has grown into a much larger company than it was a year ago, we have stayed true to our business model, focusing on rate of return and cash-generating assets. Although the year 2010 will be remembered for the level of acquisition activity, the record financial results reflected continued growth and positive returns. For the 12-month period ending December 31, 2010, Apache reported record performances in several key metrics. Highlights for the year include:

Annual daily production of oil, natural gas, and natural gas liquids averaged a record 658,000 boe/d, up 13 percent compared with 2009. Production in fourth-quarter 2010 averaged 729,000 boe/d, an increase of 24 percent from the 590,000 boe/d averaged in the fourth quarter of 2009.

Oil and gas production revenues for 2010 increased 42 percent to $12.1 billion, up from $8.6 billion in 2009, and just shy of the record $12.3 billion in 2008 when prices reached record levels.

Apache reported a record $3 billion in net income, or $8.46 per common diluted share, compared to a net loss of $292 million, or $.87 per share in the 2009 period. Apache s 2009 results were impacted by a $1.98 billion after-tax write-down of the carrying value of proved property. Apaches 2010 reported adjusted earnings(1), which exclude certain items impacting the comparability of results, were approximately $3.17 billion or $8.94 per common diluted share, up from $1.89 billion or $5.59 per common diluted share in the prior year.

Net cash provided by operating activities (operating cash flows or cash flows) totaled $6.7 billion, up 60 percent from $4.2 billion in 2009.

Estimated proved reserves at year-end 2010 were a record 2,953 MMboe, up 25 percent from 2009 estimated proved reserves of 2,367 MMboe.

(1) See *Non-GAAP Measures Adjusted Earnings* for a description of Adjusted Earnings, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and a reconciliation to this measure from Income (Loss) Attributable to Common Stock, which is presented in accordance with GAAP.

2011 Outlook

As we head into 2011, we project Apache s financial position will remain strong, given our debt-to-capitalization ratio of 25 percent, $2.4 billion of available committed borrowing capacity, projections of higher cash flows than 2010 levels and determination to hold exploration and development spending within our internally-generated cash flows. Given the present price disparity between oil and natural gas, our near-term focus is exploiting the oily and more liquids-rich properties in our portfolio and development of our gas resources in Australia and Canada, which we plan to convert to LNG and sell in the worldwide LNG market. As is the Apache way, rates of return will drive our decision making while we continue our focus on costs, operational efficiency and integrating the acquired assets. In 2011 we find ourselves with more opportunities than we can fund through internally-generated cash flow, and our challenge will be to optimize capital spending across our worldwide portfolio.

Our current 2011 capital budget includes exploration and development capital of approximately $7.5 billion. Nearly $4.0 billion is expected to be spent on projects in North America, with the remaining amount allocated across our international regions. An estimated one-third of our global capital budget is allocated to seismic and leasehold, GTP facilities and plugging and abandonment activities. While funds have been committed for certain 2011 exploration drilling, long-lead development projects and 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 other numerous industry factors and will adjust our exploration and development budgets based on changes to predicted operating cash flow. We typically review and revise our exploration and development capital budgets on a quarterly basis.

Based on the current capital spending budget and the acquisitions completed during 2010, Apache expects to increase overall production in 2011 between 13 percent and 17 percent from full-year 2010 production levels. These projections exclude the impact from any potential acquisitions or divestitures.

Table of Contents

The Company is currently planning to divest approximately $1.0 billion of properties to optimize and high-grade our existing portfolio of assets. The divestiture package will most likely include legacy conventional properties in Canada. However, as of the date of this filing we have not entered into any binding contracts to sell these assets. We generally do not budget for acquisitions because they are specific, discrete events whose occurrence and timing is unpredictable. Acquisitions may be funded from operating cash flows, credit facilities, new equity, debt issuances or a combination thereof.

Operating Highlights

Current Year

During 2010 we completed more than $11 billion of acquisitions, continued progress on developing existing core properties and expanded into new geographic areas. Through these steps, we added significantly to drilling inventory in our core areas and established a footprint in two new areas: deepwater exploration and LNG, which for us means the monetization of large gas resources at oil-linked prices.

Merger and Acquisitions of Property and Acreage

From 2007 to 2009 we were relatively absent from the acquisition market. We believed the market was overheated as oil and gas prices spiked, and the opportunities we identified did not meet our criteria for risk, reward and/or growth potential. We built our cash position while drilling our existing inventory of prospects and waiting for the right transactions to supplement it.

In June we completed the $1.05 billion acquisition of Devon Energy Corporation s oil and gas assets on the Gulf of Mexico (GOM) shelf, 75 percent of which are in fields now operated by Apache. The acquired assets include 477,000 net acres across 150 blocks. The Company believes that these well-maintained, high-quality assets fit well with Apache s existing infrastructure and play to the strengths that come with our experience operating on the shelf, exploiting the current production base and capturing upside potential.

In August we completed the $2.5 billion acquisition of oil and gas operations, acreage and infrastructure in the Permian Basin from BP plc (BP), solidifying our position as one of the most active operators in the area, where Apache has been competing for 20 years. The acquisition more than doubled our footprint in the Permian Basin to over three million gross acres.

In October we completed the $3.25 billion acquisition of substantially all of BP s upstream natural gas business in western Alberta and British Columbia, including 1.3 million net mineral and leasehold acres with significant positions in several emerging unconventional plays, such as the Noel tight-gas project, which ramped up to 100 MMcf/d by the end of the fourth quarter. We own a 100-percent working interest in the Noel project.

In November we closed on the purchase of BP assets in Egypt s Western Desert for $650 million, acquiring four development leases and one exploration concession as well as strategically-positioned infrastructure that will enable Apache to increase production from existing fields in the Western Desert.

Also in November, shareholders of Mariner Energy, Inc. (Mariner) approved the purchase of their company by Apache for stock and cash consideration totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt with the merger. Apache established a strategic presence in the deepwater Gulf of Mexico and expanded our positions in the GOM shelf, Gulf Coast and Permian Basin with the acquisition. The acquisition also provides deepwater geoscience expertise, including a core competency in subsea tieback developments, which can significantly reduce the cycle time between exploration success and initial production.

During the first quarter of 2010 Apache Canada Ltd. (Apache Canada), through its subsidiaries, closed the acquisition of a 51-percent interest in a planned LNG export terminal (Kitimat LNG facility) and a 25.5-percent interest in a partnership that owns a related proposed pipeline. EOG Resources Canada, Inc. (EOG

Table of Contents

Canada) owns the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the partnership. Upon close of the transaction, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the pipeline partnership and proposed pipeline.

In Australia, during 2010 we expanded our exploration opportunities in the Carnarvon and Exmouth basins via farm-ins to seven permits. The transactions resulted in a 58-percent increase in our net undeveloped acreage in the Carnarvon basin and added 1.9 million acres for exploration in the Exmouth basin. We will operate all of them with a 20- to 70-percent working interest.

In the North Sea, we expanded our acreage position during the year through successful bids on four exploration licenses and farming into two additional licenses with a 50-percent working interest.

Egypt 2X Gross Production Achievement

Apache s Egypt operations had another year of growth in 2010, with gross daily production rising 16 percent to 322.5 Mboe/d and net daily production rising six percent to an average of 161.7 Mboe/d for the year. During the year the Company surpassed its late-2005 goal of doubling its Western Desert production within five years. Achievement of the goal was driven in part by production from several discoveries in the Faghur and Matruh basins, infrastructure improvements including two new Salam gas trains, expansion of the capacity of the Kalabsha oil processing and transportation facilities to 40,000 b/d and completion of a major strategic compression project on Egypt s northern gas pipeline. The Faghur and Matruh basins, where the thickness of the sands and the stacked pay zones present multiple opportunities for further exploration across our acreage, will continue to be focus areas for Apache in 2011.

Van Gogh and Pyrenees Oil Fields Development

Australia s 2010 production averaged a record 79.2 Mboe/d, driven by the Apache-operated Van Gogh oil field and BHP Billiton-operated Pyrenees oil field, both of which commenced production early in 2010. The Van Gogh and Pyrenees developments utilize Floating Production Storage and Offloading (FPSO) vessels and together added 42.2 Mb/d to Apache s 2010 net oil production. Both projects have already reached payout.

Organic Growth Drivers 2011 to 2013

Australia Reindeer Field Development and Devil Creek Gas Plant

Our Reindeer field discovery is projected to commence production in 2011 upon completion of the Devil Creek Gas Plant. The Devil Creek Gas Plant is scheduled to be commissioned in the fourth quarter of 2011. This will be Western Australia s first new domestic natural gas processing hub in more than 15 years. The two-train plant is designed to process 200 MMcf/d from the Apache-operated Reindeer Field. In 2009 we entered into a gas sales contract covering a portion of the field s future production. Under the contract, Apache and our joint venture partner agreed to supply 154 Bcf of gas over seven years (approximately 60 MMcf/d) beginning in the fourth quarter of 2011 at prices substantially higher than we have historically received in Western Australia. Apache owns a 55-percent interest in the field.

Australia Halyard Field Development

Initial production from our Halyard-1 discovery well in Australia is projected for 2011 upon completion of the tie-in to the existing gas facilities on Varanus Island. The extension of this subsea infrastructure will also connect the 2010

Spar-2 discovery and allow for tie-in of future wells.

North Sea Satellite Platform

In November Apache entered into a contract to build a new satellite oil production platform for our UK Forties field. The new platform will be bridge-linked to our existing Forties Alpha installation in the Apache-operated field, located on the U.K. continental shelf. This project will provide Apache with 18 new slots for drilling additional development wells to increase the ultimate recovery from the Forties field. The satellite platform will also expand critical utility services to the field, including power generation, produced fluid processing, high-pressure gas compression for artificial lift and dehydration. Construction is projected to be complete by mid-year 2012.

Australia Macedon Field Development

The Macedon gas field s four development wells, which were completed in 2010, will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant to be built at Ashburton North in Western Australia. We have a 28-percent non-operated working interest in the field. The project, approved in 2010, is currently underway, with first production projected in 2013.

Australia Coniston Oil Field Discovery

The Coniston field is an oil accumulation near our Van Gogh field in Australia. Apache drilled 10 appraisal wells during 2009, and current plans call for subsea completions tied back to the Van Gogh field FPSO Ningaloo Vision. The project has been sanctioned for development, with first production into the domestic market projected in 2013.

North America Unconventional Gas Plays

The identification and development of significant resources in shale formations and other unconventional gas plays have introduced substantial gas supplies into North American natural gas markets for the foreseeable future. Although Apache s current production in North America is primarily conventional, near-term gas production growth will likely be driven by our activity in three large unconventional plays: shale gas in British Columbia s Horn River basin, tight sands in British Columbia s Noel area and the Granite Wash tight sands in the Anadarko basin of Oklahoma and the Texas Panhandle.

Horizontal Drilling and Completion Techniques

Apache continues to evaluate horizontal drilling potential across our acreage positions around the world, in both conventional and unconventional reservoirs. In the Permian Basin, Apache is utilizing horizontal drilling to access bypassed, unswept zones in established waterfloods. We are currently drilling our first horizontal shale well in Argentina, targeted for completion in April. In addition, we plan to drill our first horizontal well in the Western Desert of Egypt in 2011. The Company will continue to evaluate our opportunities utilizing horizontal drilling technology.

Organic Growth Drivers 2014 and Beyond

Australia Balnaves Oil Field Discovery Development

In October 2010 we announced three successful wells appraising our Balnaves-1 discovery, an oil accumulation in a separate reservoir beneath the large gas reservoirs of our Brunello gas fields (discussed below). The project is currently in the FEED stage, with plans to develop the field through a new FPSO. First production, if the decision is made to go forward with the project, is projected for 2014.

Julimar and Brunello Field Discoveries Development/Wheatstone LNG Project

In 2016, we are projecting to begin production from our operated Julimar and Brunello field gas discoveries through the Chevron operated Wheatstone LNG hub, in which we own a foundation equity partner interest of 13 percent. Apache s projected net gas sales from the fields are 160 MMcf/d and 3,250 b/d with a projected 15-year production plateau when the multi-year project is fully operational. The Wheatstone project, which is currently in FEED, will convert the gas into LNG for sale on the world market. World LNG prices are typically oil-linked prices and are currently higher than the historical gas prices in Western Australia. The project Final Investment Decision (FID) is scheduled for 2011, with first LNG projected in 2016. Nonbinding Heads of Agreements have been signed with LNG buyers and final binding sales and purchase agreements will be completed by FID.

Kitimat/Horn River Basin Development

Apache s time horizon and magnitude of our Horn River basin shale gas development is impacted by North American gas prices and the completion of the Kitimat LNG facility and a related proposed pipeline. The project has the potential to open new markets linked to oil prices in the Asia-Pacific region for gas from Apache s Canadian operations, including the Horn River basin area in northeast British Columbia. Apache Canada and EOG Canada plan to build the Kitimat LNG facility on Bish Cove near the Port of Kitimat, 400 miles north of Vancouver, British Columbia. The facility is planned for an initial minimum capacity of 700 MMcf/d, or five million metric tons of LNG per year, of which Apache Canada has reserved 51 percent. The proposed 287-mile pipeline will originate in Summit Lake, British Columbia, and is designed to link the Kitimat LNG facility to the pipeline system currently servicing western Canada s natural gas producing regions. Apache Canada will have rights to 51-percent of the capacity in the proposed pipeline. Completion of the FEED study and a final investment decision are targeted for late 2011. Construction is expected to commence in 2012, with commercial operations projected to begin in 2015.

GOM Deepwater

Apache has built deepwater experience and a record of success in Egypt, Australia and the Gulf of Mexico, on both the exploration and development sides. The GOM deepwater portfolio gained in the Mariner merger adds over 100 blocks and offers a strategic position into a significant potential growth area in the United States that can add meaningful oil reserves and production over the long term. Exploration potential is generated from Mariner s extensive track record of 36 deepwater development projects completed to date and the technological developments in seismic and facilities making exploration more predictable, lower risk and lower cost. Our pipeline of development projects include the non-operated Heidelberg (12.5-percent net working interest) and Lucius (16.67-percent net working interest) discoveries, which are still under further appraisal and study for ultimate development.

Significant Events

Impact of Deepwater Drilling Moratorium on Gulf of Mexico Operations

In 2010 the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) announced a series of moratoria, which directed oil and gas lessees and operators to cease drilling new deepwater (depths greater than 500 feet) wells on the Outer Continental Shelf (OCS), and put oil and gas lessees and operators on notice that, with certain exceptions, the BOEMRE would not consider drilling permits for deepwater wells and related activities. While the moratoria have been formally lifted, no new permits for deepwater drilling have been issued as of the date of this filing.

In addition, the BOEMRE issued new regulations in 2010 requiring additional information, documentation and analysis for all new wells on the OCS. The effect of these new regulations was to significantly slow down issuance of permits for shallow wells. Apache continues to operate under these new regulations and, through February 2011, has received 25 drilling permits for shallow wells. Current permitting activity has been slowed compared to prior-year levels, and the Company has budgeted its exploration and development activity accordingly.

Impact of Recent Political Changes on Egyptian Operations

In 2010 our operations in Egypt contributed 28 percent of our production revenue, 25 percent of total production and 10 percent of total estimated proved reserves. In 2010 we sold all of our Egyptian gas production and 34 percent of our Egyptian oil production to Egyptian General Petroleum Company (EGPC), the Egyptian state-owned oil company. The remainder of our oil was sold in the export market.

As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience that began on January 25, 2011, in the Egyptian capital of Cairo, Egyptian president Hosni Mubarak stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces assumed power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and the military would rule for six months until elections can be held. Following the advice of the U.S. State Department, Apache evacuated all non-essential personnel from Egypt. As conditions stabilized, approximately one-third of the

Table of Contents

evacuated employees returned. Apache s production, located in remote locations in the Western Desert, has continued uninterrupted; however, further changes 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 highly rated international insurers covering its investments in Egypt. In the aggregate, these policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache covering losses arising from confiscation, nationalization, and expropriation risks and 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 when actions taken by the Government of Egypt prevent Apache from exporting our share of production.

Operations Downtime

Production from our Van Gogh oil field was impacted by essential maintenance activities on the FPSO. Net fourth quarter production of 6,100 b/d was down 17,600 b/d from the previous quarter. Production resumed in the first half of February 2011.

In January 2011 a subsea pipeline connecting our Forties Bravo platform to our Charlie platform was shut-in because of corrosion. A project is underway to re-route the production through a smaller line until a new flexible pipeline is installed. This intermediate solution should be completed by the first of March 2011 and will allow us to produce approximately half of the 11,600 b/d that flowed through the main pipeline. The new main subsea pipeline will be completed by September 2011.

Table of Contents

Results of Operations

Oil and Gas Revenues

	For the Year Ended December 31,					
	2010		2009		2008	
	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution
Oil Revenues:						
United States	$ 2,683	30%	$ 1,922	32%	$ 2,751	34%
Canada	388	4%	311	5%	587	7%
North America	3,071	34%	2,233	37%	3,338	41%
Egypt	2,875	32%	2,063	34%	2,232	27%
Australia	1,296	14%	230	4%	277	3%
North Sea	1,590	18%	1,356	22%	2,085	26%
Argentina	209	2%	207	3%	225	3%
International	5,970	66%	3,856	63%	4,819	59%
Total(2)	$ 9,041	100%	$ 6,089	100%	$ 8,157	100%
Natural Gas Revenues:						
United States	$ 1,409	49%	$ 1,054	44%	$ 2,204	56%
Canada	647	23%	546	23%	1,026	26%
North America	2,056	72%	1,600	67%	3,230	82%
Egypt	495	17%	490	21%	507	13%
Australia	163	6%	133	6%	95	2%
North Sea	16	0%	13	0%	18	0%
Argentina	132	5%	133	6%	115	3%
International	806	28%	769	33%	735	18%
Total(3)	$ 2,862	100%	$ 2,369	100%	$ 3,965	100%
Natural Gas Liquids (NGL) Revenues:						
United States	$ 208	74%	$ 74	64%	$ 128	62%
Canada	39	14%	20	17%	38	19%
North America	247	88%	94	81%	166	81%

Egypt		2	1%			0%			0%
Argentina		31	11%		22	19%		40	19%
International		33	12%		22	19%		40	19%
Total	$	280	100%	$	116	100%	$	206	100%
Total Oil and Gas Revenues:									
United States	$	4,300	35%	$	3,050	36%	$	5,083	41%
Canada		1,074	9%		877	10%		1,651	14%
North America		5,374	44%		3,927	46%		6,734	55%
Egypt		3,372	28%		2,553	30%		2,739	22%
Australia		1,459	12%		363	4%		372	3%
North Sea		1,606	13%		1,369	16%		2,103	17%
Argentina		372	3%		362	4%		380	3%
International		6,809	56%		4,647	54%		5,594	45%
Total(1)	$	12,183	100%	$	8,574	100%	$	12,328	100%

(1) Financial derivative hedging activities increased oil and gas production revenues for 2010 and 2009 by $165.3 million and $180.8 million, respectively, and decreased oil and gas production revenues for 2008 by $458.7 million.

Table of Contents

(2) Financial derivative hedging activities decreased 2010 oil revenues by $57.0 million, increased 2009 oil revenues by $45.2 million and decreased 2008 oil revenues by $450.8 million.

(3) Financial derivative hedging activities increased natural gas revenues for 2010 and 2009 by $222.3 million and $135.6 million, respectively, and decreased natural gas revenues for 2008 by $7.9 million.

Production

	For the Year Ended December 31,				
	2010	Increase (Decrease)	2009	Increase (Decrease)	2008
Oil Volume b/d:					
United States	96,576	+8%	89,133	−1%	89,797
Canada	14,581	−4%	15,186	−11%	17,154
North America	111,157	+7%	104,319	−2%	106,951
Egypt	99,122	+8%	92,139	+38%	66,753
Australia	45,908	+369%	9,779	+19%	8,249
North Sea	56,791	−7%	60,984	+3%	59,494
Argentina	9,956	−13%	11,505	−7%	12,409
International	211,777	+21%	174,407	+19%	146,905
Total(1)	322,934	+16%	278,726	+10%	253,856
Natural Gas Volume Mcf/d:					
United States	730,847	+10%	666,084	−2%	679,876
Canada	396,005	+10%	359,235	+2%	352,731
North America	1,126,852	+10%	1,025,319	−1%	1,032,607
Egypt	374,858	+3%	362,618	+38%	263,711
Australia	199,729	+9%	183,617	+49%	123,003
North Sea	2,391	−12%	2,703	+3%	2,637
Argentina	184,830	0%	184,557	−6%	195,651
International	761,808	+4%	733,495	+25%	585,002
Total(2)	1,888,660	+7%	1,758,814	+9%	1,617,609
NGL Volume b/d:					
United States	13,777	+125%	6,136	+3%	5,986
Canada	2,884	+38%	2,089	+1%	2,076
North America	16,661	+103%	8,225	+2%	8,062

Egypt	82	N/A		N/A	
Argentina	3,180	−2%	3,241	+12%	2,887
International	3,262	+1%	3,241	+12%	2,887
Total	19,923	+74%	11,466	+5%	10,949
BOE per day(3)					
United States	232,161	+13%	206,284	−1%	209,097
Canada	83,466	+8%	77,147	−1%	78,018
North America	315,627	+11%	283,431	−1%	287,115
Egypt	161,680	+6%	152,575	+38%	110,704
Australia	79,196	+96%	40,382	+40%	28,750
North Sea	57,190	−7%	61,435	+3%	59,934
Argentina	43,941	−3%	45,505	−5%	47,904
International	342,007	+14%	299,897	+21%	247,292
Total	657,634	+13%	583,328	+9%	534,407

(1) Approximately 12 percent of 2010 oil production was subject to financial derivative hedges, compared to 10 percent in 2009 and 19 percent in 2008.

(2) Approximately 23 percent of 2010 gas production was subject to financial derivative hedges, compared to nine percent in 2009 and 20 percent in 2008.

(3) The 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.

Pricing

	For the Year Ended December 31,				
	2010	Increase (Decrease)	2009	Increase (Decrease)	2008
Average Oil price Per barrel:					
United States	$ 76.13	+29%	$ 59.06	−29%	$ 83.70
Canada	72.83	+30%	56.16	−40%	93.53
North America	75.69	+29%	58.64	−31%	85.28
Egypt	79.45	+30%	61.34	−33%	91.37
Australia	77.32	+20%	64.42	−30%	91.78
North Sea	76.66	+26%	60.91	−36%	95.76
Argentina	57.47	+16%	49.42	0%	49.46
International	77.21	+27%	60.58	−32%	89.63
Total(1)	76.69	+28%	59.85	−32%	87.80
Average Natural Gas price Per Mcf:					
United States	$ 5.28	+22%	$ 4.34	−51%	$ 8.86
Canada	4.48	+7%	4.17	−47%	7.94
North America	5.00	+17%	4.28	−50%	8.55
Egypt	3.62	−2%	3.70	−30%	5.25
Australia	2.24	+13%	1.99	−5%	2.10
North Sea	18.64	+42%	13.15	−30%	18.78
Argentina	1.96	0%	1.96	+22%	1.61
International	2.90	+1%	2.87	−16%	3.43
Total(2)	4.15	+12%	3.69	−45%	6.70
Average NGL Price Per barrel:					
United States	$ 41.45	+26%	$ 33.02	−44%	$ 58.62
Canada	36.61	+43%	25.54	−48%	49.33
North America	40.62	+31%	31.12	−45%	56.23
Egypt	69.75	N/A		N/A	
Argentina	27.08	+44%	18.76	−50%	37.83
International	28.15	+50%	18.76	−50%	37.83
Total	38.58	+40%	27.63	−46%	51.38

(1) Reflects per-barrel decrease of $.48 in 2010, an increase of $.44 in 2009 and a reduction of $4.85 in 2008 from financial derivative hedging activities.

(2) Reflects per-Mcf increase of $.32 in 2010 and $.21 in 2009 and a reduction of $.01 in 2008 from financial derivative hedging activities.

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 2010 were 28 percent above 2009 with economies stabilizing or growing across the globe. Apache uses financial instruments to manage a portion of its exposure to fluctuations in crude oil prices, particularly in North America. In 2010, 12 percent of our oil production was subject to financial derivative hedges, reducing revenues by $57 million. In 2009, 10 percent of our oil production was hedged, increasing oil revenue by $45 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.

While the market price received for crude oil varies among geographic areas, crude oil tends to trade at a global price. With the exception of Argentina, price movements for all types and grades of crude oil generally move in the same direction. In Australia, Apache continues to directly market all of our crude oil production into Australian domestic and international markets at prices indexed to Dated Brent benchmark crude oil prices plus a premium, which are typically above NYMEX oil prices. 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, but producers retain a value-added tax collected from buyers, effectively increasing price realizations by 21 percent.

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. 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 2010, 23 percent of our gas production was subject to financial derivative hedges, increasing revenues by $222 million. In 2009, nine percent of our gas production was hedged, increasing gas revenue by $136 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.

Apache primarily sells natural gas into the North American market, where spot prices increased 17 percent compared to 2009, and various international markets, where our average contracted prices rose just one percent from 2009. Our primary markets include North America, Egypt, Australia and Argentina.

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, with a majority under an industry pricing formula indexed to Dated Brent crude oil with a maximum gas price of $2.65 per MMBtu. On up to 100 MMcf/d of gross production, there is no price cap for our gas under a legacy contract, which expires at the end of 2012. Overall, the region averaged $3.62 per Mcf in 2010.

Australia has 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, market prices received on recent contracts, including our Reindeer field, are substantially higher than historical levels.

In Argentina we receive government-regulated pricing on a substantial portion of our production. The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. During 2010 we realized an average price of $1.20 per Mcf on government-regulated sales. The majority of the remaining volumes were sold at market-driven prices, which averaged $2.65 per Mcf in 2010.

Our overall average realized price for 2010 was $1.96 per Mcf, the same as our 2009 average realized price and 22 percent higher than 2008 average realized price ($1.61 per Mcf).

During 2010 Apache signed three Gas Plus contracts totaling 63 MMcf/d of gross production from fields in the Neuquén and Rio Negro Provinces. Gas Plus is a program instituted by the Argentine government to encourage new gas supplies through the development of tight sands and unconventional reserves. The first contract, for 10 MMcf/d at $4.10 per MMBtu, has been extended through 2011 for 11 MMcf/d at $4.10 per

Table of Contents

MMbtu. Our other two Gas Plus contracts, for a total of 53 MMcf/d at $5.00 per MMBtu, are projected to commence in the first quarter of 2011. The gas supplying the Gas Plus program contracts is required to come from wells drilled in the projects approved fields and formations. We believe the Gas Plus program, coupled with changing market conditions, point to improving price realizations going forward.

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

2010 vs. 2009 During 2010 crude oil revenues totaled $9.0 billion, $2.9 billion higher than the 2009 total of $6.1 billion, driven by a 16-percent increase in worldwide production and a 28-percent increase in average realized prices. Average daily production in 2010 was 322.9 Mb/d, with prices averaging $76.69 per barrel. Crude oil represented 74 percent of our 2010 oil and gas production revenues and 49 percent of our equivalent production, compared to 71 and 48 percent, respectively, in the prior year. Higher realized prices contributed $1.7 billion to the increase in full-year revenues, while higher production volumes added another $1.2 billion.

Worldwide oil production increased 44.2 Mb/d, driven by a 36.1 Mb/d increase in Australia on new production from the Van Gogh and Pyrenees discoveries, which were brought online in the first quarter of 2010. U.S. production increased eight percent, or 7.4 Mb/d, with the Permian region up 4.4 Mb/d on properties added from the BP acquisitions, the Mariner merger and drilling and recompletion activity. The Gulf Coast region added 1.8 Mb/d from properties acquired in the Devon acquisition, the Mariner merger and drilling and recompletion activity. Central region production increased 1.2 Mb/d on drilling and recompletion activity. Gross production in Egypt increased 17 percent, while net production was up only eight percent, a function of the mechanics of our production-sharing contracts. Net production increased 7.0 Mb/d on production gains in the Shushan, Matruh and numerous other concessions. Additional capacity at the Kalabsha oil processing facility, as well as processing of condensate-rich gas through the Salam Gas Plant allowed by the new Jade manifold, allowed for much of the production gains. North Sea production decreased 4.2 Mb/d on natural decline and downtime. Production in Argentina and Canada declined 1.5 Mb/d and .6 Mb/d, respectively, on natural decline.

2009 vs. 2008 Crude oil accounted for 48 percent of our equivalent production and 71 percent of oil and gas production revenues during 2009, compared to 48 and 66 percent, respectively, for 2008. Impacted by dramatically lower oil prices realized during the global financial crisis that began in late 2008, crude oil revenues for 2009 totaled $6.1 billion, $2.1 billion lower than the prior year. A 32-percent decline in average realized prices reduced revenues $2.6 billion, of which $528 million was offset by the impact of 10 percent production growth.

Worldwide production increased 24.9 Mb/d despite curtailed capital spending, which was 40 percent lower than 2008. Egypt s oil production increased 38 percent or 25.4 Mb/d on exploration successes in numerous concessions, most notably East Bahariya Extension, South Umbarka, Matruh, Northeast Abu Gharadig Extension and Khalda, waterflood projects and increased condensate from additional Qasr gas flowing through the new processing trains at the Salam Gas Plant. Australia s production was up 1.5 Mb/d, as production was restored following completion of repairs at Varanus Island. North Sea production increased 1.5 Mb/d on strong drilling results, which offset the impact of unplanned downtime at the Bravo Platform, which lowered 2009 average daily oil production by 2.6 Mb/d. The Bravo Platform was down for most of the fourth quarter for pipeline repairs. Production declined 2.0 Mb/d in Canada, .9 Mb/d in Argentina and .7 Mb/d in the U.S., as natural decline offset results from our curtailed 2009 drilling programs.

Natural Gas Revenues

2010 vs. 2009 Natural gas revenues for 2010 of $2.9 billion were $493 million higher than 2009 on a 12-percent increase in realized prices and a seven-percent increase in production volumes. Realized prices in 2010 averaged $4.15 per Mcf and the $.46 per Mcf increase added $297 million to revenues. Worldwide production rose 130 MMcf/d, adding another $197 million to revenues.

Worldwide gas production rose in all of our core gas-producing regions. U.S. production was up 64.8 MMcf/d, or 10 percent. Driven by new drilling, recompletion activity and properties acquired from Devon and the Mariner

Table of Contents

merger, Gulf Coast region production was up 38.2 MMcf/d. Permian region production was up 20.1 MMcf/d, primarily on volumes from properties acquired from BP. Central region production was up 6.5 MMcf/d as additional production from new drilling and recompletions outpaced natural decline. An active drilling and completion program at Horn River and additional volumes from properties acquired from BP led Canada region production 36.8 MMcf/d higher. Production in Australia was up 16.1 MMcf/d on higher customer takes from our John Brookes field. In Egypt, gross production was up 14 percent, while net production rose only three percent, a function of our production-sharing contracts. The 12.2 MMcf/d increase in net production relative to 2009 was attributable to several factors, including a successful drilling and recompletion program on our Matruh concession, additional volumes processed through the Obaiyed Gas Plant and a full year of additional capacity provided by the completion of two new gas trains at the Salam Gas Plant. Argentina s production was up marginally as production from new drilling and recompletions was mostly offset by natural decline.

2009 vs. 2008 Natural gas accounted for 50 percent of our equivalent production and 28 percent of our oil and gas production revenues during 2009, compared to 50 and 32 percent, respectively, for 2008. Impacted by dramatically lower gas prices realized during the global financial crisis that began in late 2008, gas revenues for 2009 totaled $2.4 billion, down $1.6 billion from 2008. A 45-percent decline in average realized prices reduced revenues $1.8 billion, partially offset by the $184 million impact of a nine percent increase in production.

Worldwide production grew 141 MMcf/d, driven by a 99 MMcf/d increase in Egypt s net production and a 61 MMcf/d increase in Australia. Egypt s gas production was up 38 percent on exploration successes at our Khalda and Matruh concessions and additional plant and pipeline capacity. Additional capacity provided by the combination of two new processing trains at the Salam Gas Plant and completion of a project to increase compression on the Northern Gas Pipeline allowed previously discovered wells in our Khalda Concession Qasr field to come online. Australia s 49 percent production increase was driven by production restorations following completion of repairs to the Varanus Island facility. Canada s gas production increased 6 MMcf/d from drilling and recompletion activities and a lower effective royalty rate, partially offset by natural decline. Argentine production decreased 11 MMcf/d on natural decline and lower capital spending levels. U.S. daily production declined 14 MMcf/d. Production in the Gulf Coast decreased 8 MMcf/d as production shut-in for facility, rig and third-party downtime repairs reduced the 2009 production by 30 MMcf/d, which more than offset net production gains from drilling results. Our Central region s production declined 6 MMcf/d primarily a result of the region s curtailed drilling program, which was deferred until service costs fell in line with lower commodity prices. Most of the regions drilling activity occurred in the second half of the year.

Table of Contents

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 relevance.

	Year Ended December 31,			Year Ended December 31,		
	2010	2009	2008	2010	2009	2008
		(In millions)			(Per boe)	
Depreciation, depletion and amortization:						
Oil and gas property and equipment						
Recurring	$ 2,861	$ 2,202	$ 2,358	$ 11.92	$ 10.34	$ 12.06
Additional		2,818	5,334		13.24	27.27
Other assets	222	193	158	.92	.91	.81
Asset retirement obligation accretion	111	105	101	.46	.49	.52
Lease operating expenses	2,032	1,662	1,910	8.47	7.81	9.76
Gathering and transportation	178	143	157	.73	.67	.80
Taxes other than income	690	580	985	2.88	2.72	5.03
General and administrative expenses	380	344	289	1.58	1.62	1.48
Merger, acquisitions & transition	183			.77		
Financing costs, net	229	242	166	.95	1.13	.85
Total	$ 6,886	$ 8,289	$ 11,458	$ 28.68	$ 38.93	$ 58.58

Depreciation, Depletion and Amortization

The following table details the changes in recurring depreciation, depletion and amortization (DD&A) of oil and gas properties between 2010 and 2008:

	Recurring DD&A (In millions)
2008	$ 2,358
Volume change	150
Rate change	(306)
2009	$ 2,202
Volume change	317
Rate change	342
2010	$ 2,861

2010 vs. 2009 Recurring full-cost depletion expense increased $659 million on an absolute dollar basis: $342 million on higher rate and $317 million from additional production. Our full-cost depletion rate increased $1.58 to $11.92 per boe as costs to acquire, find and develop reserves exceeded our historical cost basis.

2009 vs. 2008 Recurring full-cost depletion expense decreased $156 million on an absolute dollar basis: $306 million on lower rate, partially offset by an increase of $150 million from higher production. Our full-cost depletion rate decreased $1.72 to $10.34 per boe. The decrease in rate was driven by a $5.33 billion non-cash write-down of the carrying value of our December 31, 2008, proved property balances in the U.S., U.K. North Sea, Canada and Argentina and a $2.82 billion non-cash write-down of the carrying value of our March 31, 2009, proved oil and gas property balances in the U.S. and Canada. The impact of the write-downs was partially offset by 2009 drilling and finding costs, which exceeded our historical cost basis.

Table of Contents

Lease Operating Expenses

Lease operating expenses (LOE) include several components: 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 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties and in areas with remote plants and facilities. All production in Australia and the North Sea and nearly 90 percent from the U.S. Gulf Coast region comes from offshore properties. Workovers accelerate production; hence, activity generally increases with higher commodity prices. Foreign exchange rate fluctuations generally 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.

2010 vs. 2009 Our 2010 LOE increased $370 million from 2009, or 22 percent on an absolute dollar basis. On a per-unit basis, LOE increased eight percent with a 22 percent increase on higher costs, offset by a 14 percent decline related to increased production. The rate was impacted by the items below:

	Per boe
2009 LOE	$ 7.81
Acquisitions, net of associated production	.27
Foreign exchange rate impact	.22
Equipment rental	.22
Workover costs	.16
Stock-based compensation	.14
Labor and pumper costs	.08
Material	.07
Power and fuel	.07
Incentive compensation	.05
Other	.15
Other increased production	(.77)
2010 LOE	$ 8.47

2009 vs. 2008 Our 2009 LOE decreased $248 million from 2008. LOE per boe was down 20 percent: 13 percent on lower cost and seven percent on higher production. The rate was impacted by the items below:

	Per boe
2008 LOE	$ 9.76
Higher production	(.68)
Workover costs	(.36)

Foreign exchange rate impact		(.33)
Power and fuel		(.32)
Labor and pumper costs		(.10)
Hurricane repairs		(.10)
Other		(.06)
2009 LOE	$	7.81

Table of Contents

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,		
	2010	2009	2008
	(In millions)		
U.S.	$ 42	$ 36	$ 40
Canada	75	53	63
North Sea	25	26	28
Egypt	31	23	21
Argentina	5	5	5
Total Gathering and Transportation	$ 178	$ 143	$ 157

2010 vs. 2009 Gathering and transportation costs increased $35 million from 2009. The increase in the U.S. resulted from an increase in both the volumes transported under arrangements where we pay costs directly to third parties and in rates. The increase in Canada resulted from an increase in volumes, rate and foreign exchange rates. North Sea costs were down on lower production and foreign exchange rates. Egypt costs increased as a result of higher shipping, handling and pipeline fees as compared to the prior year.

2009 vs. 2008 Gathering and transportation costs decreased $14 million from 2008. The decreases in the U.S. and Canada resulted from a decrease in both the volumes transported under arrangements where we pay costs directly to third parties and in rates. North Sea costs were down on foreign exchange rates. Egypt costs increased as a result of retroactive terminal fees claimed by EGPC, partially offset by a decrease in export cargoes as more crude oil was purchased by EGPC for domestic use in the latter part of 2009.

Taxes Other Than Income

Taxes other than income primarily comprises U.K. Petroleum Revenue Tax (PRT), severance taxes on properties onshore and in state or provincial waters off the coast of the U.S. and Australia and ad valorem taxes on properties in the U.S. and Canada. Severance taxes are generally based on a percentage of oil and gas production revenues, while the U.K. PRT is assessed on net receipts (revenues less qualifying operating costs and capital spending) from the Forties field 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: Freehold

Table of Contents

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,		
	2010	2009	2008
		(In millions)	
U.K. PRT	$ 422	$ 383	$ 695
Severance taxes	142	88	168
Ad valorem taxes	80	55	71
Other taxes	46	54	51
Total Taxes other than income	$ 690	$ 580	$ 985

2010 vs. 2009 Taxes other than income were $110 million higher than 2009. U.K. PRT was $39 million more than 2009 on a 10 percent increase in net profits driven by higher oil revenues. Severance taxes increased $54 million from higher taxable revenues in the U.S., predominantly resulting from acquisitions, and consistent with higher realized oil and natural gas prices relative to the prior year. The $25 million increase in ad valorem taxes resulted from higher taxable valuations in the U.S. associated with increases in oil and natural gas prices relative to the prior year and the BP and Devon acquisitions and Mariner merger.

2009 vs. 2008 Taxes other than income were $405 million lower than 2008. U.K. PRT was $312 million less than 2008 on a 43 percent decrease in net profits, driven by lower oil revenues and lower operating and capital costs. The decrease in severance taxes resulted from lower taxable revenues in the U.S., consistent with the lower realized oil and natural gas prices relative to the prior year. The $16 million decrease in ad valorem taxes resulted from lower taxable valuations associated with decreases in oil and natural gas prices.

General and Administrative Expenses

2010 vs. 2009 General and administrative (G&A) expenses were $36 million higher in 2010 than in 2009. On a per boe basis, G&A expenses decreased two percent as the effect of higher volumes more than offset the increase in costs. G&A expense was impacted by the following:

2009 G&A	$ 1.62
Workforce reduction costs	(.19)
Stock-based compensation	.15
Other incentive compensation	.06
Kitimat LNG administrative costs	.03
Other corporate costs	.11
Increased production	(.20)
2010 G&A	$ 1.58

2009 vs. 2008 G&A expenses were $55 million higher in 2009 than in 2008. On a per boe basis, G&A expenses increased nine percent: 19 percent on higher costs, offset by a 10 percent reduction on higher volumes. G&A expense was impacted by the following:

2008 G&A	$ 1.48
Workforce reduction costs	.20
Stock-based compensation	.17
Other incentive compensation	(.06)
Other corporate costs	(.03)
Increased production	(.14)
2009 G&A	$ 1.62

Table of Contents

Merger, Acquisitions & Transition

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:

Separation and retention costs	$ 114
Investment banking fees	42
Other costs	27
2010 Merger, Acquisitions & Transition	$ 183

Merger, acquisitions & transition costs during 2008 and 2009 were not material.

Financing Costs, Net

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

	For the Year Ended December 31,		
	2010	**2009**	**2008**
	(In millions)		
Interest expense	$ 345	$ 309	$ 280
Amortization of deferred loan costs	17	6	4
Capitalized interest	(120)	(61)	(94)
Interest income	(13)	(12)	(24)
Total Financing costs, net	$ 229	$ 242	$ 166

2010 vs. 2009 Financing costs, net decreased $13 million from 2009. The decrease is primarily related to a $59 million increase in capitalized interest, the result of additional unproved balances from the BP acquisitions and Mariner merger. This decrease is partially offset by a $36 million increase in interest expense from three debt issuances in 2010 and $11 million higher amortization of deferred loan costs related to the new debt and repayment of the Australian project financing facility.

2009 vs. 2008 Financing costs, net increased $76 million from 2008. The increase in cost is primarily the result of a $29 million increase in interest expense related to higher average outstanding debt balances, a $33 million reduction in capitalized interest related to lower unproved property balances and completion of several long-term construction projects, and a $12 million decrease in interest income on a lower average cash balance and lower interest rates.

Provision for Income Taxes

2010 vs. 2009 The provision for income taxes totaled $2.2 billion in 2010 compared to $611 million in 2009. The effective rates for 2010 and 2009 were skewed by the effect of currency exchange rates on our foreign deferred tax liabilities and other net tax settlements. Total taxes and the effective rate for 2009 were also impacted by the magnitude of the taxes related to the full-cost write-down in that year. Excluding these items, the 2010 and 2009 effective tax rates were comparable at 40.75 percent and 39.75 percent, respectively.

2009 vs. 2008 The provision for income taxes totaled $611 million in 2009 compared to $220 million in 2008. Total taxes and the effective rates for each period were skewed by the magnitude of the taxes related to the 2009 and 2008 full-cost write-downs, the effect of currency exchange rates on our foreign deferred tax liabilities and other net tax settlements. Excluding these items, the 2009 and 2008 effective tax rates were comparable at 39.75 percent and 39.58 percent, respectively.

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,	
	2010	2009
	(In millions, except share data)	
Income (Loss) Attributable to Common Stock (GAAP)	$ 3,000	$ (292)
Adjustments:		
Foreign currency fluctuation impact on deferred tax expense	52	198
Merger, acquisitions & transition, net of tax(1)	120	
Additional depletion, net of tax(2)		1,981
Adjusted Earnings (Non-GAAP)	$ 3,172	$ 1,887
Adjusted Earnings Per Share (Non-GAAP)		
Basic	$ 9.02	$ 5.62
Diluted	$ 8.94	$ 5.59
Average Number of Common Shares		
Basic	352	336
Diluted	359	338

(1) Merger, acquisitions & transition costs recorded in 2010 totaled $183 million pre-tax, for which a tax benefit of $63 million was recognized. The tax effect was calculated utilizing the statutory rates in effect in each country where costs were incurred.

(2) Additional depletion (non-cash write-down of the carrying value of proved property) recorded in 2009 was $2.82 billion pre-tax, for which a deferred tax benefit of $837 million was recognized. The tax effect of the write-down of the carrying value of proved property (additional depletion) in 2009 was calculated utilizing the statutory rates in effect in each country where a write-down occurred.

Acquisitions and Divestitures

2010 Activity

In the fourth quarter of 2010 Apache acquired 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. Additionally, Mariner has accumulated acreage in emerging unconventional shale oil resources in the U.S.

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 blocks.

During the first quarter of 2010 Apache Canada, through its subsidiaries, closed the acquisition of a 51-percent interest in the Kitimat LNG facility and a 25.5-percent interest in a partnership that owns a related proposed pipeline. EOG Resources Canada owns the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the partnership. Upon close of the transaction, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the pipeline partnership and proposed pipeline.

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

2009 Activity

During the second quarter of 2009 Apache announced the acquisition of nine Permian Basin oil and gas fields with then-current net production of 3,500 boe/d from Marathon Oil Corporation for $187.4 million, subject to normal post-closing adjustments. Estimated reserves acquired in connection with the acquisition totaled 19.5 MMboe. These long-lived fields fit well with Apache s existing properties in the Permian Basin, particularly in Lea County, New Mexico, and will provide the Company many years of drilling opportunities. The effective date of the transaction was January 1, 2009.

2008 Activity

There was no major acquisition activity during 2008; however, the Company completed several divestiture transactions. On January 29, 2008, the Company completed the sale of its interest in Ship Shoal blocks 349 and 359 on the outer continental shelf of the Gulf of Mexico to W&T Offshore, Inc. for $116 million. On January 31, 2008, the Company completed the sale of non-strategic oil and gas properties in the Permian Basin of West Texas to Vanguard Permian, LLC for $78 million. On April 2, 2008, the Company completed the sale of non-strategic Canadian properties to Central Global Resources for C$112 million.

Capital Resources and Liquidity

Operating cash flows is a primary source of liquidity. Apache s 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 revenues, earnings and cash flows, capital spending 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 or as impactive as 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 continuously to fund exploration and development projects and acquisitions, which are necessary to offset the inherent declines in production and proven reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of our exploration and development activities or our ability to acquire additional reserves at reasonable costs. For a discussion of risk factors related to our business and operations, please see Part I, Item 1A Risk Factors.

Table of Contents

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 ability to access the debt and equity capital markets is supported by its investment-grade credit ratings.

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.

Apache s primary uses of cash are exploration, development and acquisition of oil and gas properties, costs necessary to maintain ongoing operations, repayment of principal and interest on outstanding debt and payment of dividends. We fund our exploration and development activities primarily through operating cash flows and budget capital expenditures based on projected cash flows.

See 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.

Table of Contents

Sources and Uses of Cash

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

	Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 6,726	$ 4,224	$ 7,065
Net commercial paper and bank loan borrowings	318		
Sale of short-term investments		792	
Sales of property and equipment		2	308
Project financing draw-downs		250	100
Fixed-rate debt borrowings	2,470		796
Proceeds from issuance of common stock	2,258		
Proceeds from issuance of depositary shares	1,227		
Common stock activity	70	29	32
Treasury stock activity	9	6	4
Other	27	29	39
	13,105	5,332	8,344
Uses of Cash and Cash Equivalents:			
Capital expenditures(1)	4,922	3,631	5,823
Purchase of short-term investments			792
Acquisitions:			
Devon properties	1,018		
BP properties	6,429		
Mariner	787		
Other	126	310	150
Net commercial paper and bank loan repayments		2	200
Project financing repayment	350		
Payments on fixed-rate notes	1,023	100	
Redemption of preferred stock		98	
Dividends	226	209	239
Cost of debt and equity transactions	17		
Other	121	115	85
	15,019	4,465	7,289
Increase (decrease) in cash and cash equivalents	$ (1,914)	$ 867	$ 1,055

(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 is our primary source of capital and liquidity and is impacted, both in the short-term and the long-term, by highly volatile oil and natural gas prices.

Apache s average natural gas price realizations fluctuated throughout 2010, dipping from a high of $4.84 per Mcf in February to a low of $3.89 in September before increasing to $4.19 in December. Average realized natural gas prices for the year rose 12 percent over 2009 to $4.15 per Mcf. Our average crude oil realizations saw an increase throughout the year from a low of $70.68 per barrel in May 2010, peaking in December at $86.01 per barrel. Crude oil prices averaged $76.69 per barrel for 2010, up 28 percent from 2009.

In order to manage the variability in cash flows, we utilize commodity hedges. At the end of 2010, we had hedged an average of just over 375,000 MMBtu per day of our 2011 North American natural gas production. The volumes were primarily hedged using fixed-price swaps at an average price of approximately $6.25 per MMBtu. For perspective, the natural gas hedges represent 24 percent of fourth-quarter 2010 North America daily gas production and 16 percent worldwide.

For liquids, we had an average of just under 98,000 b/d of oil production hedged for 2011. Crude oil production was primarily hedged using collars that had average floor and ceiling prices of approximately $69 and $97 per barrel, respectively. In addition, 20,000 b/d of our North Sea Forties field production will be sold under a physical delivery contract subject to a minimum price of $70 a barrel and a ceiling price of $99 a barrel. For perspective, the combined 2011 financial derivatives represent approximately 35 percent of fourth-quarter 2010 worldwide daily oil production.

For additional information regarding our derivative contracts, 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 quantitative and qualitative information regarding our use of derivatives to manage commodity price risk, please see Commodity Risk in Part II, Item 7A of this Form 10-K.

The factors affecting 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.

For 2010, operating cash flows totaled $6.7 billion, up $2.5 billion from 2009. The primary driver of the increase was a $3.6 billion increase in oil and gas revenues on both higher production and prices, especially oil. This was partially offset by higher cash-based expenses, including merger and transition expenses associated with our acquisitions in 2010, and higher income tax payments in 2010.

For a detailed discussion of commodity prices, production, costs 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.

Commercial Paper and Bank Loans

The Company has available a $2.95 billion commercial paper program, which generally enables Apache to borrow funds for up to 270 days at competitive interest rates. As of December 31, 2010, the Company had $913 million in commercial paper outstanding. For further discussion of our commercial paper program, please see Liquidity below and Note 5 Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Upon consummation of our merger with Mariner, we assumed credit lines with outstanding borrowings of approximately $632 million. Commercial paper was issued to repay this amount, and credit lines assumed from Mariner were terminated prior to year-end 2010.

Short-term Investments

We occasionally invest in highly-liquid, short-term investments until funds are needed to further supplement our operating cash flows. At December 31, 2008, we had $792 million invested in U.S. Treasury securities with original maturities greater than three months but less than one year. These securities matured on April 2, 2009. None were held at December 31, 2010 or 2009.

Project Financing

One of the Company s Australian subsidiaries had a secured revolving syndicated credit facility for its Van Gogh and Pyrenees oil developments offshore Western Australia. The outstanding balance under the facility was

$350 million at December 31, 2009. We paid off $50 million of the facility in June 2010 and the remaining balance in December 2010. For a more detailed discussion of this facility and information regarding our available committed borrowing capacity, please see Liquidity below.

Fixed-Rate Debt

On August 20, 2010, the Company issued $1.5 billion principal amount of senior unsecured 5.1-percent notes maturing September 1, 2040. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay borrowings under a bridge facility and the Company s commercial paper program that were used to finance the BP acquisitions.

On December 3, 2010, the Company issued $500 million principal amount of senior unsecured 3.625-percent notes maturing February 1, 2021, and $500 million principal amount of senior unsecured 5.25-percent notes maturing February 1, 2042. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to redeem the outstanding public debt of $1.0 billion assumed upon completion of Apache s acquisition of Mariner on November 10, 2010.

Proceeds from Issuance of Common Stock

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 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.

Proceeds from Issuance of Mandatory Convertible 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, with an initial liquidation preference of $1,000 per share (equivalent to $50 liquidation preference per depositary share). The Company received proceeds of approximately $1.2 billion, after underwriting discounts and before expenses, from the sale.

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. Apache routinely adjusts capital expenditure budgets in response to these adjusted operating cash flow forecasts and market trends in drilling and acquisitions costs.

Historically, we have used a combination of operating cash flows, borrowings under lines of credit and 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.

	Year Ended December 31, 2010	2009	2008
	(In millions)		
Exploration and Development:			
United States	$ 1,623	$ 929	$ 2,183
Canada	860	412	705
North America	2,483	1,341	2,888
Egypt	757	676	853
Australia	624	602	880
North Sea	617	375	459
Argentina	240	140	318
Chile	20	11	27
International	2,258	1,804	2,537
Worldwide Exploration and Development Costs	4,741	3,145	5,425
Gathering, Transmission and Processing Facilities (GTP):			
Canada	159	83	29
Egypt	182	151	571
Australia	162	69	54
Argentina	3	2	5
Total GTP Costs	506	305	659
Asset Retirement Costs	459	288	514
Capitalized Interest	120	61	94
Capital Expenditures, excluding Acquisitions	5,826	3,799	6,692
Acquisitions, including GTP	11,557	310	150
Asset Retirement Costs Acquired	847	5	
Total Capital Expenditures	$ 18,230	$ 4,114	$ 6,842

Exploration and Development As a result of Apache s determination to not outspend our operating cash flows, we curtailed 2009 capital expenditures in response to the decline in commodity prices and financial uncertainty in the global economy at the outset of 2009. Our 2010 drilling and development budgets were increased in response to recovering commodity prices and projected increases in operating cash flows. As a result, worldwide E&D expenditures for 2010 were 51 percent higher than 2009.

E&D spending in North America, which was up 85 percent from the prior year, totaled 52 percent of worldwide E&D spending, up from 43 percent in 2009. U.S. E&D expenditures were $694 million or 75 percent higher than year-ago levels on expanded drilling activities in the Permian region and horizontal drilling in the Granite Wash play in the Central region. Activity related to newly acquired properties in the Permian and Gulf Coast regions also contributed to increased E&D expenditures late in the year. E&D spending in Canada more than doubled, increasing to $860 million as the Company actively developed and increased its acreage positions in several plays including the Horn River basin.

E&D expenditures outside of North America increased 25 percent over 2009 to nearly $2.3 billion. E&D spending in the North Sea was up $242 million over 2009 levels on construction of the Bacchus subsea tie-back project and on the Forties Alpha satellite platform and ongoing upgrades to existing platforms. Argentina expenditures were up on additional drilling and development activity. Egypt was $81 million higher than the prior year on continued drilling activity in the Matruh and Faghur basins, where we have announced numerous recent discoveries. E&D expenditures in Australia and Chile were up marginally, increasing over prior-year levels by $22 million and $9 million, respectively.

Acquisitions We completed over $11 billion of acquisitions in 2010 compared to $310 million in 2009. We also assumed $847 million in asset retirement costs. Acquisition capital expenditures occur as attractive opportunities arise and, therefore, vary from year to year. For information regarding our acquisitions, please see Significant Acquisitions and Divestitures above and Note 2 Acquisitions in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Asset Retirement Costs In 2010 we recorded $459 million of additional future asset retirement costs associated with our worldwide drilling programs and upward revisions to prior-year estimates for timing and costs.

Gathering, Transmission and Processing Facilities (GTP) We invested $506 million in GTP in 2010 compared to $305 million in 2009. GTP expenditures in Australia consisted of construction activity at the Devil Creek Gas Plant and the FEED study for the Wheatstone LNG project. Activity in Canada was centered in the Horn River basin, with expenditures for compressor stations, a water treatment facility, gathering systems and a gas processing plant. Expenditures in Egypt included the initial phases of the Kalabsha oil processing facility. In addition, approximately $517 million of the value of our 2010 acquisitions is associated with GTP.

Dividends

The Company has paid cash dividends on its common stock for 46 consecutive years through 2010. Future dividend payments will depend on the Company s level of earnings, financial requirements and other relevant factors. Common stock dividends paid during 2010 totaled $206 million, compared with $201 million in 2009 and $234 million in 2008. The 2008 period included a special non-recurring cash dividend of 10 cents per common share paid on March 18, 2008. The Company also made dividend payments of $20 million on the Company s Series D Preferred Stock in 2010.

Liquidity

	At December 31,	
(In millions, except percentages)	**2010**	**2009**
Cash and cash equivalents	$ 134	$ 2,048
Total debt	8,141	5,067
Shareholders equity	24,377	15,779
Available committed borrowing capacity	2,387	2,300
Floating-rate debt/total debt	12%	7%
Percent of total debt to capitalization	25%	24%

Our liquidity and financial position have not been materially affected by recent uncertainty in the credit markets. We believe that losses from non-performance are unlikely to occur; however, we are not able to predict sudden changes in the creditworthiness of the financial institutions with which we do business. Twenty-seven of 28 banks with lending commitments to the Company have credit ratings of at least single-A, which in some cases is based on government support. There is no assurance that the financial condition of these banks will not deteriorate or that the government guarantee will be maintained. We closely monitor the ratings of the 28 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.

Cash and Cash Equivalents

We had $134 million in cash and cash equivalents at December 31, 2010. At December 31, 2010, $120 million of cash was held by foreign subsidiaries and approximately $14 million was held by Apache Corporation and

U.S. subsidiaries. The cash held by foreign subsidiaries is subject to additional U.S. income taxes if repatriated. Almost all of the cash is denominated in U.S. dollars and, at times, is invested in highly liquid, investment-grade securities, with maturities of three months or less at the time of purchase. We intend to use cash from our international subsidiaries to fund international projects.

Debt

At December 31, 2010, outstanding debt, which consisted of notes, debentures, commercial paper and uncommitted bank lines, totaled $8.1 billion. Current debt consists of $46 million borrowed under uncommitted money market/overdraft lines of credit in the U.S. and Argentina. We have $46 million of debt maturing in 2011, $400 million maturing in 2012, $1.8 billion maturing in 2013, $350 million maturing in 2015, and the remaining $5.6 billion maturing intermittently in years 2016 through 2096.

Debt-to-Capitalization Ratio

The Company s debt-to-capitalization ratio as of December 31, 2010 was 25 percent.

Available Credit Facilities

As of December 31, 2010, the Company had unsecured committed revolving syndicated bank credit facilities totaling $3.3 billion, of which $1.0 billion matures in August 2011 and $2.3 billion matures in May 2013. The facilities consist of a $1.0 billion 364-day facility, a $1.5 billion facility and a $450 million facility in the U.S., a $200 million facility in Australia and a $150 million facility in Canada. The $1.5 billion and the $450 million credit facilities also allow the company to borrow under competitive auctions. The U.S. credit facilities are used to support Apache s commercial paper program.

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. The negative covenants include restrictions on the Company s ability to create liens and security interests on our 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 five percent of the Company s consolidated assets, or approximately $2.2 billion as of December 31, 2010. There are no restrictions on incurring liens in countries other than 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 our ability to guarantee debt of entities not within our 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 $100 million or has any unpaid, non-appealable judgment against it in excess of $100 million. The Company was in compliance with the terms of the credit facilities as of December 31, 2010.

At the Company s option, the interest rate for the facilities, excluding the 364-day facility, is based on a base rate, as defined, or LIBOR plus a margin determined by the Company s senior long-term debt rating. In the case of the 364-day facility, the margin over LIBOR varies based upon prices reported in the credit default swap market with respect to Apache s one-year indebtedness and the rating for Apache s senior, unsecured long-term debt.

In 2010, one of the Company s Australian subsidiaries repaid $350 million under its amortizing secured revolving syndicated credit facility for its Van Gogh and Pyrenees oil developments offshore Western Australia. Upon repayment of the facility, all commitments under the facility were terminated and assets secured by the facility were released.

At December 31, 2010, the margin over LIBOR for committed loans was .19 percent on the $1.5 billion facility and .23 percent on the $450 million facility in the U.S., the $200 million facility in Australia and the $150 million facility in Canada. If the total amount of the loans borrowed under the $1.5 billion facility equals or exceeds 50 percent of the total facility commitments, then an additional .05 percent will be added to the margins over LIBOR. If the total amount of the loans borrowed under all of the other three facilities equals or exceeds 50 percent of the total facility commitments, then an additional .10 percent will be added to the margins over LIBOR. The Company also pays quarterly facility fees of .06 percent on the total amount of the $1.5 billion facility and

.07 percent on the total amount of the other three facilities. The facility fees vary based upon the Company s senior long-term debt rating.

Commercial Paper Program

In August 2010 the Company increased its commercial paper program by $1 billion from $1.95 billion to $2.95 billion. The commercial paper program generally enables Apache to borrow funds for up to 270 days at competitive interest rates. Our 2010 weighted-average interest rate for commercial paper was .37 percent. If the Company is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, the Company s U.S. credit facilities are available as a 100-percent backstop. The commercial paper program is fully supported by available borrowing capacity under U.S. committed credit facilities, which expire in 2011 and 2013. As of December 31, 2010, the Company had $913 million in commercial paper outstanding.

Contractual Obligations

We are subject to various financial obligations and commitments in the normal course of operations. These contractual obligations represent known future cash payments that we are required to make and relate primarily to long-term debt, operating leases, pipeline transportation commitments and international commitments. The Company expects to fund these contractual obligations with cash generated from operating activities.

The following table summarizes the Company s contractual obligations as of December 31, 2010. For additional information regarding these obligations, please see Note 5 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	Note Reference	Total	2011	2012-2014	2015-2016	2017 & Beyond
			(In millions)			
Debt, at face value	Note 5	$ 8,190	$ 46	$ 2,213	$ 766	$ 5,165
Interest payments	Note 5	7,774	417	1,107	659	5,591
Drilling rig commitments	Note 8	392	303	89		
Purchase obligations	Note 8	833	574	259		
E&D commitments	Note 8	575	235	308	32	
Firm transportation agreements	Note 8	809	137	423	170	79
Office and related equipment	Note 8	166	34	70	25	37
Oil and gas operations equipment	Note 8	476	85	146	55	190
Other	Note 8	5	5			
Total Contractual Obligations(a)(b)(c)(d)		$ 19,220	$ 1,836	$ 4,615	$ 1,707	$ 11,062

(a) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $2.9 billion. For additional information regarding asset retirement obligation, please see Note 4 Asset Retirement Obligation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(b) This table does not include the Company s $12 million net liability for outstanding derivative instruments valued as of December 31, 2010. For additional information regarding derivative instruments, 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.

(c) This table does not include the Company s pension or postretirement benefit obligations. For additional information regarding pension and postretirement benefit obligations, 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.

(d) This table does not include the Company s tax reserves. For additional information regarding tax reserves, please see Note 6 Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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 $135 million for environmental remediation and approximately $14 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 $106 million accrued as of December 31, 2010, 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. The liability reflecting this potential charge has been fully accrued.

Off-Balance Sheet Arrangements

Apache does not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions.

Insurance Program

We maintain insurance coverage that includes coverage for physical damage to our oil and gas properties, third party liability, workers compensation and employers liability, general liability, sudden pollution and other coverage. 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.

In general, our current insurance policies covering physical damage to our oil and gas assets provide $250 million per occurrence with an additional $250 million per year. 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, includes a self-insured retention of 40 percent of the losses above a $100 million deductible, and is limited to no more than two storms per year. In addition, our policies covering physical damage to our North Sea oil and gas assets provide $250 million per occurrence with an additional $750 million per year.

Our various insurance policies also provide coverage for, among other things, liability related to negative environmental impacts of a sudden pollution event in the amount of $750 million per occurrence, charterer s legal liability, in the amount of $1 billion per occurrence, aircraft liability in the amount of $750 million per occurrence, and general liability, employer s liability and auto liability in the amount of $500 million per occurrence. Our service agreements, including drilling contracts, generally indemnify Apache for injuries and death of the service provider s employees as well as contractors and subcontractors hired by the service provider.

Our insurance policies generally renew in January and June of each year. In light of the recent catastrophic accident in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. 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 in the future or unavailable on terms that we believe are economically acceptable.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and highly rated international insurers covering its investments in Egypt. In the aggregate, these policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache covering losses arising from confiscation, nationalization, and expropriation risks and 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 when actions taken by the Government of Egypt prevent Apache from exporting our share of production.

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. Following is a discussion of Apache s most critical accounting policies:

Reserves Estimates

Effective December 31, 2009, Apache adopted revised oil and gas disclosure requirements set forth by the U.S. Securities and Exchange Commission (SEC) in Release No. 33-8995, Modernization of Oil and Gas Reporting and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Topic 932, Extractive Industries Oil and Gas. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGL s 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, 2010 and 2009 were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month, held flat for the life of the production, except where prices are defined by contractual arrangements. Reserves as of December 31, 2008 were estimated using prices in effect at the end of that year, in accordance with SEC guidance in effect prior to the issuance of the Modernization Rules.

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 related 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. 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, 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 due to unpredictable events such as economic growth or retraction, weather and climate. Our average monthly crude oil realizations saw a gradual increase from a low of $70.68 per barrel in May 2010, peaking in December at $86.10. In 2010 crude oil prices averaged $76.69 per barrel up 28 percent from 2009. Our average monthly natural gas price realizations fluctuated throughout 2010, dipping from a high of $4.84 per Mcf in February to a low of $3.89 in September before increasing to $4.19 in December. Average realized prices in 2010 for natural gas increased 12 percent to $4.15 per Mcf.

For 2010 approximately 23 percent of our natural gas production was subject to financial derivative hedges. As of year-end 2010 we had just over 375,000 MMBtu per day of our projected 2011 North American natural gas production hedged. For perspective, these hedges cover 24 percent of fourth-quarter 2010 North American daily production, or 16 percent of worldwide production.

Approximately 12 percent of our 2010 crude oil production was subject to financial derivative hedges. We entered 2011 having hedged approximately 98,000 b/d of oil production. In addition, Apache North Sea, Ltd. entered into a 2011 physical sales contract to deliver 20 thousand barrels of oil per day under a collar pricing arrangement. For perspective, the combined 2011financial derivatives represent approximately 35 percent of our fourth-quarter 2010 worldwide daily oil volumes.

Apache may use futures contracts, swaps, options and fixed-price physical contracts to hedge its commodity prices. Realized gains or losses from the Company s price-risk management activities are recognized in oil and gas production revenues when the associated production occurs. Apache does not hold or issue derivative instruments for trading purposes.

On December 31, 2010, the Company had open natural gas derivative hedges in an asset position with a fair value of $454 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $104 million, while a 10 percent decrease in prices would increase the fair value by approximately $104 million. The Company also had open crude oil derivatives in a liability position with a fair value of $466 million. A 10 percent increase in oil prices would increase the liability by approximately $356 million, while a 10 percent decrease in prices would decrease the liability by approximately $298 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2010. For notional volumes and terms associated with the Company s derivative contracts, 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.

Apache conducts its risk management activities for its commodities under the controls and governance of its risk management policy. The Risk Management Committee approves and oversees these controls, which have been implemented by designated members of the treasury department. The treasury and accounting departments also provide separate checks and reviews on the results of hedging activities. Controls for our commodity risk management activities include limits on credit, limits on volume, segregation of duties, delegation of authority and a number of other policy and procedural controls.

Interest Rate Risk

On December 31, 2010, the Company s debt with fixed interest rates represented approximately 88 percent of total debt. As a result, the interest expense on approximately 12 percent of Apache s debt will fluctuate based on short-term interest rates. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $782,000.

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 largely under fixed-price Australian dollar contracts. Approximately half the costs incurred for Australian operations are paid in U.S. dollars. In Canada, the majority of oil and gas production is sold under Canadian dollar contracts. The majority of the costs incurred are paid in Canadian dollars. The 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 converted into Argentine pesos at the time of payment. Revenue and disbursement transactions denominated in Australian dollars, Canadian dollars, British pounds, Egyptian 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, Egyptian pound or Argentine peso as of December 31, 2010, would result in a foreign currency net loss or gain, respectively, of approximately $16 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, 2010, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, plan, believe, or continue or similar terminology. believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- the market prices of oil, natural gas, NGLs and other products or services;
- our commodity hedging arrangements;
- the integration of Mariner and the BP properties;
- increased scrutiny from regulatory agencies due to the BP acquisition;
- 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;

68

Table of Contents

capital expenditure and other contractual obligations;

the significant transaction and acquisition costs related to the Mariner and BP property acquisitions;

currency exchange rates;

weather conditions;

inflation rates;

the availability of goods and services;

legislative or regulatory changes;

the impact on our operations due to the change in government in Egypt;

terrorism;

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. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

Table of Contents

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

The financial statements and supplementary financial information required to be filed under this item are presented on pages F-1 through F-67 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, 2010, 2009 and 2008, included in this report, have been audited by Ernst & Young LLP, registered public accounting firm, as stated in their audit report appearing herein.

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, 2010, 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, 2010, 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 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 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, 2010, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. *OTHER INFORMATION*

None.

Table of Contents

PART III

ITEM 10. *DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT*

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 2011 annual meeting of stockholders (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 2010. 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 stockholder 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.

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*

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 ACCOUNTANT 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, AND REPORTS ON FORM 8-K*

(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).
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).

Exhibit No.	Description
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	Bylaws of Registrant, as amended August 6, 2009 (incorporated by reference to Exhibit 3.2 to Registrant s Quarterly Report on Form 10-Q for quarter ended June 30, 2009, SEC File No. 001-4300).
4.1	Form of Certificate for Registrant s Common Stock (incorporated by reference to Exhibit 4.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, SEC File No. 001-4300).
4.2	Form of Certificate for the 6.00% Mandatory Convertible Preferred Stock, Series D (incorporated by reference to Exhibit A of Exhibit 3.3 to Registrant s Registration Statement on Form 8-A, dated July 29, 2010, SEC File No. 001-4300).
4.3	Form of 3.625% Notes due 2021 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.4	Form of 5.250% Notes due 2042 (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.5	Form of 5.100% Notes due 2040 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated August 17, 2010, filed on August 20, 2010, SEC File No. 001-4300).
4.6	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).
4.7	Amendment No. 1, dated as of January 31, 2006, to the Rights Agreement dated as of December 31, 1996, between Apache Corporation, a Delaware corporation, and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.) (incorporated by reference to Exhibit 4.4 to Registrant s Amendment No. 1 to Registration Statement on Form 8-A, dated January 31, 2006, SEC File No. 001-4300).
4.8	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).
4.9	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).
4.10	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).
4.11	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).

Exhibit No.	Description
4.12	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).
4.13	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).
4.14	Form of Apache Corporation November 10, 2010 First Non-Qualified Stock Option Agreements for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.6 to Registrant s Current Report on Form S-8 filed on November 10, 2010, SEC File No. 001-4300).
4.15	Form of Apache Corporation November 10, 2010 Second Non-Qualified Stock Option Agreements for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.7 to Registrant s Current Report on Form S-8 filed on November 10, 2010, SEC File No. 001-4300).
4.16	Form of Apache Corporation November 10, 2010 Non-StatutoryStock Option Agreements for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.8 to Registrant s Current Report on Form S-8 filed on November 10, 2010, SEC File No. 001-4300).
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).
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 SociétéGénérale, as U.S. Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.1 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 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).

Table of Contents

Exhibit No.	Description
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, Citisecurities 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 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
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, JP Morgan 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	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).
10.11	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).
10.12	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).
10.13	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).
* 10.14	Apache Corporation 401(k) Savings Plan, as amended and restated, dated October 28, 2010.
* 10.15	Amendment to Apache Corporation 401(k) Savings Plan, dated December 30, 2010, effective as of November 10, 2010, except as otherwise specified.
10.16	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).

10.17	Apache Corporation 2007 Omnibus Equity Compensation Plan, as amended and restated July 13, 2010, effective December 31, 2009 (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, SEC File No. 001-4300).
10.18	Apache Corporation 1998 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).

Exhibit No.	Description
10.19	Apache Corporation 2000 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).
10.20	Apache Corporation 2003 Stock Appreciation Rights Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.5 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2008, SEC File No. 001-4300).
10.21	Apache Corporation 2005 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.6 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2008, Commission File No. 001-4300).
10.22	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).
10.23	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).
10.24	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).
10.25	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).
10.26	Apache Corporation Deferred Delivery Plan, as amended and restated July 13, 2010, effective January 1, 2009 (incorporated by reference to Exhibit 10.6 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, SEC File No. 001-4300).
10.27	Apache Corporation Non-Employee Directors Compensation Plan, as amended and restated November 20, 2008, effective as of January 1, 2009 (incorporated by reference to Exhibit 10.38 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.28	Apache Corporation Outside Directors Retirement Plan, as amended and restated July 14, 2010, effective January 1, 2009 (incorporated by reference to Exhibit 10.7 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, SEC File No. 001-4300).
10.29	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).
10.30	Apache Corporation Non-Employee Directors Restricted Stock Units Program Specifications, dated August 14, 2008, pursuant to Apache Corporation 2007 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.9 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).
10.31	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).
10.32	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).

10.33	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).

Table of Contents

Exhibit No.	Description
10.34	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).
10.35	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).
10.36	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).
10.37	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).
10.38	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).
10.39	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).
10.40	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).
10.41	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).
10.42	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).
10.43	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).
10.44	Restricted Stock Unit Award Agreement, dated February 9, 2011, between Registrant and Mr. 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).
*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
*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 of Principal Executive Officer
*31.2	Certification of Principal Financial Officer
*32.1	Certification of Principal Executive Officer and Principal Financial Officer

Table of Contents

Exhibit No.	Description
*99.1	Report of Ryder Scott Company L.P., Petroleum Consultants
**101	The following materials from the Apache Corporation s Annual Report on Form 10-K for the year ended December 31, 2010, formatted in XBRL (Extensible Business Reporting Language): (i) Statement of Consolidated Operations, (ii) Statement of Consolidated Cash Flows, (iii) Consolidated Balance Sheet, (iv) Statement of Consolidated Shareholders Equity, and (v) Notes to Consolidated Financial Statements, tagged as blocks of text.

* Filed herewith.

** Furnished 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.

Table of Contents

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, 2011

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 G. Steven Farris	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 28, 2011
/s/ THOMAS P. CHAMBERS Thomas P. Chambers	Executive Vice President and Chief Financial Officer (principal financial officer)	February 28, 2011
/s/ REBECCA A. HOYT Rebecca A. Hoyt	Vice President, Chief Accounting Officer and Controller (principal accounting officer)	February 28, 2011
/s/ FREDERICK M. BOHEN Frederick M. Bohen	Director	February 28, 201
/s/ RANDOLPH M. FERLIC Randolph M. Ferlic	Director	February 28, 2011
/s/ EUGENE C. FIEDOREK	Director	

Eugene C. Fiedorek		February 28, 2011
/s/ A.D. FRAZIER, JR.	Director	February 28, 2011
A.D. Frazier, Jr.		

Name	Title	Date
/s/ PATRICIA ALBJERG GRAHAM Patricia Albjerg Graham	Director	February 28, 2011
/s/ SCOTT D. JOSEY Scott D. Josey	Director	February 28, 2011
/s/ CHANSOO JOUNG Chansoo Joung	Director	February 28, 2011
/s/ JOHN A. KOCUR John A. Kocur	Director	February 28, 2011
/s/ GEORGE D. LAWRENCE George D. Lawrence	Director	February 28, 2011
/s/ F. H. MERELLI F. H. Merelli	Director	February 28, 2011
/s/ RODMAN D. PATTON Rodman D. Patton	Director	February 28, 2011
/s/ CHARLES J. PITMAN Charles J. Pitman	Director	February 28, 2011

Table of Contents

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, 2010. 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, 2010.

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, 2011

Table of Contents

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, 2010 and 2009, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009, the Company adopted SEC Release 33-8995 and the amendments to ASC Topic 932, Extractive Industries Oil and Gas, resulting from ASU 2010-03 (collectively, the Modernization Rules).

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, 2010, 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, 2011, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2011

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, 2010, 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 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, 2010, 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, 2010 and 2009, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2010 of Apache Corporation and subsidiaries, and our report dated February 28, 2011, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2011

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31, 2010	2009	2008
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil and gas production revenues	$ 12,183	$ 8,574	$ 12,328
Other	(91)	41	62
	12,092	8,615	12,390
OPERATING EXPENSES:			
Depreciation, depletion and amortization			
Recurring	3,083	2,395	2,516
Additional		2,818	5,334
Asset retirement obligation accretion	111	105	101
Lease operating expenses	2,032	1,662	1,910
Gathering and transportation	178	143	157
Taxes other than income	690	580	985
General and administrative	380	344	289
Merger, acquisitions & transition	183		
Financing costs, net	229	242	166
	6,886	8,289	11,458
INCOME BEFORE INCOME TAXES	5,206	326	932
Current income tax provision	1,222	842	1,456
Deferred income tax provision (benefit)	952	(231)	(1,236)
NET INCOME (LOSS)	3,032	(285)	712
Preferred stock dividends	32	7	6
INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 3,000	$ (292)	$ 706
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 8.53	$ (0.87)	$ 2.11
Diluted	$ 8.46	$ (0.87)	$ 2.09

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

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31, 2010	2009	2008
	(In millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 3,032	$ (285)	$ 712
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	3,083	5,213	7,850
Asset retirement obligation accretion	111	105	101
Provision for (benefit from) deferred income taxes	952	(231)	(1,236)
Other	190	183	(51)
Changes in operating assets and liabilities, net of effects of acquisitions:			
Receivables	(496)	(187)	571
Inventories	35	(5)	(22)
Drilling advances	(28)	(143)	29
Deferred charges and other	(141)	148	(324)
Accounts payable	214	(180)	(71)
Accrued expenses	(309)	(330)	(457)
Deferred credits and noncurrent liabilities	83	(64)	(37)
NET CASH PROVIDED BY OPERATING ACTIVITIES	6,726	4,224	7,065
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(4,407)	(3,326)	(5,144)
Additions to gathering, transmission and processing facilities	(515)	(306)	(679)
Acquisition of Marathon properties		(181)	
Acquisition of Devon properties	(1,018)		
Acquisition of BP properties and facilities	(6,429)		
Mariner Energy, Inc. merger	(787)		
Acquisitions, other	(126)	(129)	(150)
Short-term investments		792	(792)
Restricted cash		14	(14)
Proceeds from sale of oil and gas properties		3	308
Other, net	(121)	(114)	(64)
NET CASH USED IN INVESTING ACTIVITIES	(13,403)	(3,247)	(6,535)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Commercial paper, credit facility and bank notes, net	(32)	248	(100)
Fixed-rate debt borrowings	2,470		796
Payments on fixed-rate notes	(1,023)	(100)	
Proceeds from issuance of common stock	2,258		
Proceeds from issuance of mandatory convertible preferred stock	1,227		
Dividends paid	(226)	(209)	(239)

Common stock activity	70	28	31
Redemption of preferred stock		(98)	
Other	19	21	37
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	4,763	(110)	525
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,914)	867	1,055
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	2,048	1,181	126
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 134	$ 2,048	$ 1,181
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 187	$ 243	$ 171
Income taxes paid, net of refunds	1,170	686	1,695

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

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31, 2010	December 31, 2009
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 134	$ 2,048
Receivables, net of allowance	2,134	1,546
Inventories	564	533
Drilling advances	259	231
Prepaid assets and other	389	228
	3,480	4,586
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	57,904	44,267
Unproved properties and properties under development, not being amortized	5,048	1,479
Gathering, transmission and processing facilities	4,212	3,189
Other	582	493
	67,746	49,428
Less: Accumulated depreciation, depletion and amortization	(29,595)	(26,527)
	38,151	22,901
OTHER ASSETS:		
Goodwill	1,032	189
Deferred charges and other	762	510
	$ 43,425	$ 28,186
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 779	$ 397
Accrued operating expense	163	90
Accrued exploration and development	1,367	923
Accrued compensation and benefits	231	152
Current debt	46	117
Asset retirement obligations	407	147
Derivative instruments	194	128
Other	337	439
	3,524	2,393

LONG-TERM DEBT	8,095	4,950
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	4,249	2,765
Asset retirement obligation	2,465	1,637
Other	715	662
	7,429	5,064
COMMITMENTS AND CONTINGENCIES (Note 8)		
SHAREHOLDERS EQUITY:		
Preferred stock, no par value, 5,000,000 shares authorized, 6% Cumulative Mandatory Convertible, Series D, $1,000 per share liquidation preference, 1,265,000 shares issued and outstanding in 2010	1,227	
Common stock, $0.625 par, 430,000,000 shares authorized, 383,668,297 and 344,076,790 shares issued, respectively	240	215
Paid-in capital	8,864	4,634
Retained earnings	14,223	11,437
Treasury stock, at cost, 1,276,555 and 7,639,818 shares, respectively	(36)	(217)
Accumulated other comprehensive loss	(141)	(290)
	24,377	15,779
	$ 43,425	$ 28,186

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

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED SHAREHOLDERS EQUITY

	Comprehensive Income (Loss)	Series B Preferred Stock	Series D Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
					(In millions)				
BALANCE AT DECEMBER 31, 2007		$ 98	$	$ 213	$ 4,367	$ 11,458	$ (238)	$ (520)	$ 15,378
Comprehensive income:									
Net income	$ 712					712			712
Postretirement, net of income tax benefit of $7	(8)							(8)	(8)
Commodity hedges, net of income tax expense of $301	550							550	550
Comprehensive income	$ 1,254								
Cash dividends:									
Preferred						(6)			(6)
Common ($.70 per share)						(234)			(234)
Common shares issued				1	37				38
Treasury shares issued, net							10		10
Compensation expense					94				94
Other					(25)				(25)
BALANCE AT DECEMBER 31, 2008		98		214	4,473	11,930	(228)	22	16,509
Comprehensive loss:									
Net loss	$ (285)					(285)			(285)
Postretirement, net of income tax benefit of $5	(4)							(4)	(4)
Commodity hedges, net of income tax benefit of $171	(308)							(308)	(308)
Comprehensive loss	$ (597)								
Cash dividends:									

Preferred						(7)			(7)
Common ($.60 per share)						(201)			(201)
Preferred stock redemption		(98)							(98)
Common shares issued				1	15				16
Treasury shares issued, net					(5)		11		6
Compensation expense					128				128
Other					23				23
BALANCE AT DECEMBER 31, 2009				215	4,634	11,437	(217)	(290)	15,779
Comprehensive income:									
Net income	$ 3,032					3,032			3,032
Postretirement, net of income tax expense of $2	(2)							(2)	(2)
Commodity hedges, net of income tax expense of $62	151							151	151
Comprehensive income	$ 3,181								
Cash dividends:									
Preferred						(32)			(32)
Common ($.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

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

Table of Contents

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 seven countries, spanning five continents: the United States, Canada, Egypt, the U.K. North Sea, Australia, Argentina and on the Chilean side of the island of Tierra del Fuego.

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 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 fair value of acquired assets and liabilities (see Note 2 Acquisitions), the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (see Note 12 Supplemental Oil and Gas Disclosures), asset retirement obligations (see Note 4 Asset Retirement Obligation) and income taxes (see Note 6 Income Taxes).

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, 2010 and 2009, Apache had $134 million and $2.0 billion, 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 approximate 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, 2010 and 2009, the Company had an allowance for doubtful accounts of $48 million and $38 million, respectively.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventories

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

Oil and Gas Property

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, including salaries and benefits, but does not include any costs related to production, general corporate overhead or similar activities. Historically, total capitalized internal costs in any given year have not been material to total oil and gas costs capitalized in such year. Apache capitalized $321 million, $219 million and $236 million of these internal costs in 2010, 2009 and 2008, respectively. 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.

Costs Excluded

Oil and gas unevaluated properties and properties under development include costs that are excluded from costs being depreciated or amortized. These costs represent investments in unproved properties and major development projects in which the Company owns a direct interest. Apache excludes these costs on a country-by-country basis until proved reserves are found, until it is determined that the costs are impaired or until major development projects are placed in service. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. 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. Also, geological and geophysical costs not associated with specific properties are recorded to proved property. For international operations 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.

Ceiling Test

Under the existing full-cost method of accounting, a ceiling test is performed each quarter. The test establishes a limit (ceiling), on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization (DD&A) and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is the estimated after-tax future net cash flows from proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet. If capitalized costs exceed this ceiling, the excess is charged to expense and reflected as additional DD&A in the accompanying statement of consolidated operations.

Effective December 31, 2009, Apache adopted revised oil and gas disclosure requirements set forth by the U.S. Securities and Exchange Commission (SEC) in Release No. 33-8995, Modernization of Oil and Gas Reporting and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC)

Topic 932, Extractive Industries Oil and Gas. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The estimate of after-tax future net cash flows as of December 31, 2010 and 2009 is 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 month in 2010 and 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. Prior to adoption of the Modernization Rules, effective in the fourth quarter of 2009, estimated after-tax future net cash flows were calculated using commodity prices in effect at the end of each quarter.

As of December 31, 2010, capitalized costs did not exceed the ceiling limitation, and no write-down was indicated. Excluding the effect of cash flow hedges in calculating the ceiling limitation at December 31, 2010, capitalized costs still would not have exceeded the ceiling limitation. See Note 12 Supplemental Oil and Gas Disclosures for a discussion of the calculation of estimated future net cash flows.

Under then-existing full-cost accounting rules, the Company recorded 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 on December 31, 2008, as a result of the ceiling test limitations. Under those same rules, which were in effect for the first three quarterly reporting periods in 2009, the Company recorded an additional $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. These write-downs are reflected as additional DD&A expense in the accompanying statement of consolidated operations. Excluding the effects of cash flow hedges in calculating the ceiling limitation, the write-downs as of December 31, 2008 and March 31, 2009 would have been $5.9 billion ($4.0 billion net of tax) and $3.4 billion ($2.4 billion net of tax), respectively.

Gathering, Transmission and Processing Facilities

The Company assesses the carrying amount of its gathering, transmission and processing facilities annually and whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. If the carrying amount of these facilities is less than the sum of the undiscounted cash flows expected to result from their use and eventual disposition, an impairment loss is recorded through a charge to expense. Gathering, transmission and processing facilities totaled $4.2 billion and $3.2 billion at December 31, 2010 and 2009, respectively. No impairment of gathering, transmission and processing facilities was recognized during 2010, 2009 or 2008.

Depreciation, Depletion and Amortization

DD&A of oil and gas properties is calculated quarterly, 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 times the cost of those reserves. The result is to recognize expense at the same pace that the reservoirs are actually depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated DD&A, estimated future development costs (future costs to access and develop reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value.

Gas 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 20 years. Accumulated depreciation for these assets totaled $1.3 billion and $1.1 billion at December 31, 2010 and 2009, respectively.

Asset Retirement Obligation

The initial estimated asset retirement obligation (ARO) related to properties is recognized as a liability, with an associated increase in property and equipment for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated ARO changes, an adjustment is recorded to both the ARO and the asset retirement cost. Revisions in estimated liabilities can result from changes in

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling ARO.

Capitalized Interest

Interest is capitalized on oil and gas investments in unproved properties and in-progress exploration and development activities. Major construction projects also qualify for interest capitalization up until the time the assets are ready for service. Capitalized interest is calculated by multiplying the Company s weighted-average interest rate on debt by the amount of qualifying costs. For projects under construction that carry their own financing, interest is calculated using the interest rate related to the project financing. Interest and related costs are capitalized until each project is complete. Capitalized interest cannot exceed gross interest expense. Capitalized interest associated with unproved properties is transferred to proved properties along with the associated unproved property balance. When major construction projects are completed, the associated capitalized interest is amortized over the useful life of the related asset. Capitalized interest totaled $120 million, $61 million and $94 million in 2010, 2009 and 2008, respectively.

Business Combinations

Apache records all business combinations in accordance with ASC Topic 805, Business Combinations. A business combination includes all transactions or other events in which control of one or more businesses is obtained. ASC Topic 805 requires the recognition and measurement of identifiable assets acquired and liabilities assumed and recording deferred taxes for any differences between the fair values of net assets acquired and carryover tax basis of assets and liabilities. Any excess of the purchase price over the estimated fair values of assets and liabilities is recorded as goodwill.

Purchase Price Allocation

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. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained. These amounts will be finalized as soon as possible, but no later than one year from the acquisition date. 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.

Goodwill

Goodwill represents 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. The Company assesses the carrying amount of goodwill by testing the goodwill for impairment annually and when impairment indicators arise. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each unit is determined as of the date of the impairment test and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then goodwill is written down to the implied fair value of the goodwill through a charge to expense. Goodwill totaled $1.0 billion and $189 million at December 31, 2010 and 2009, respectively. Goodwill of $843 million was recorded in the U.S. in 2010 as a result of the merger with Mariner Energy, Inc. (Mariner), as discussed in Note 2 Acquisitions. As of December 31, 2010 and 2009, approximately $103 million and $86 million were recorded in Canada and Egypt, respectively. Each country was assessed as a reporting unit. No impairment of goodwill was recognized during 2010, 2009 or 2008.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Payable

Included in accounts payable at December 31, 2010 and 2009, are liabilities of approximately $191 million and $98 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 collectibility of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

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 gas (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 $33 million, $34 million and $56 million, for 2010, 2009 and 2008, 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 that the Company believes are minimal credit risks, 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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 under accounting standards, 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 some or all of the unremitted earnings will be remitted, the Company will then recognize taxes on those earnings.

Foreign Currency Translation

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 translation 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.

The Company accounts for foreign currency gains and losses in accordance with ASC Topic 830, Foreign Currency Matters. Foreign currency translation gains and losses related to current taxes payable and deferred tax liabilities are recorded as a component of provision for income taxes. In 2010, the Company recorded additional net tax expense of $111 million, including a current tax expense of $2 million and deferred tax expense of $109 million, in connection with foreign currency translation gains and losses. Included in deferred tax expense for 2010 is approximately $57 million of tax expense attributable to realized foreign currency transactions. In 2009, Apache recorded an additional net tax expense of $195 million, including a current benefit of $3 million and a deferred expense of $198 million. In 2008, Apache recorded an additional tax benefit of $400 million, including a current benefit of $3 million and a deferred benefit of $397 million. For further discussion, see Note 6 Income Taxes. All other foreign currency translation 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 included in Other

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

under Revenues and Other in the statement of consolidated operations netted to a loss in 2010 of $39 million, and gains of $11 million and $38 million in 2009 and 2008, respectively.

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.

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.

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.

Diluted EPS also includes the impact of unvested share appreciation plans. For awards in which the share price goals have already been achieved, shares are included in diluted EPS using the treasury stock method. For those awards in which the share price goals have not been achieved, the number of contingently issuable shares included in diluted EPS is based on the number of shares, if any, using the treasury stock method, that would be issuable if the market price of the Company s stock at the end of the reporting period exceeded the share price goals under the terms of the plan. The diluted EPS calculation also 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. In 2003 and 2004, the Company also granted cash-based stock appreciation rights. These plans and related accounting policies are defined and described more fully in Note 7 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 $28 million, $16 million and $47 million as financing cash inflows in 2010, 2009 and 2008, respectively.

Treasury Stock

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

Recently Issued Accounting Standards Not Yet Adopted

All new accounting pronouncements previously issued have been adopted as of or prior to December 31, 2010.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. ACQUISITIONS

2010 Activity

Kitimat LNG Project

During the first quarter of 2010 Apache Canada Ltd. (Apache Canada), through its subsidiaries, purchased a 51-percent interest in a planned LNG export terminal (Kitimat LNG facility) and a 25.5-percent interest in a partnership that owns a related proposed pipeline. In the second quarter of 2010 EOG Resources Canada, Inc. (EOG Canada), through its wholly-owned subsidiaries, acquired the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the pipeline partnership from Pacific Northern Gas Ltd (PNG). Under the terms of the agreement, PNG will operate and maintain the planned pipeline under a seven-year agreement with Apache Canada and EOG Canada with provisions for five-year renewals. It also includes a 20-year transportation service arrangement which may require Apache Canada and EOG Canada, under certain circumstances, to use a portion of PNG s current pipeline capacity. Upon close of the transaction, expected in the second quarter of 2011, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the proposed pipeline.

Apache Canada and EOG Canada plan to build the Kitimat LNG facility on Bish Cove near the Port of Kitimat, 400 miles north of Vancouver, British Columbia. The facility is planned for an initial minimum capacity of 700 MMcf/d, or five million metric tons of LNG per year, of which Apache Canada has reserved 51 percent. The proposed 287-mile pipeline will originate in Summit Lake, British Columbia, and is designed to link the Kitimat LNG facility to the pipeline system currently servicing western Canada s natural gas producing regions. Apache Canada will have rights to 51-percent of the capacity in the proposed pipeline. Completion of the FEED study and a final investment decision are targeted for late 2011. Construction is expected to commence in 2012, with commercial operations projected to begin in 2015.

Gulf of Mexico Shelf Acquisition

On June 9, 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. The acquired assets include 477,000 net acres across 150 blocks and estimated proved reserves of 41 million barrels of oil equivalent (MMboe) (unaudited). Approximately half of the estimated net proved reserves were liquid hydrocarbons, and seven major fields account for 90 percent of the estimated proved reserves. Virtually all of the production is located in fields in water depths less than 500 feet, and Apache now operates 75 percent of the production. Apache allocated $653 million of the purchase price to proved property, $361 million to unproved property and $4 million to gas plant facilities. Apache also recorded abandonment obligations for the properties of $233 million. The acquisition was funded primarily from existing cash balances.

Mariner Energy, Inc. Merger

On November 10, 2010, Apache acquired Mariner, an independent exploration and production company, in a stock and cash transaction. Mariner s assets and liabilities are 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. Additionally, Mariner has accumulated acreage in emerging unconventional shale oil resources in the U.S.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The total amount of cash and shares of Apache common stock paid and issued, respectively, pursuant to the Merger Agreement was fixed, and Mariner stockholders received (on an aggregate basis) 0.17043 of a share of Apache common stock, par value $0.625 per share, and $7.80 in cash for each share of Mariner common stock, with cash being paid in lieu of any fractional shares of Apache common stock. Upon completion of the Merger, each outstanding employee option to purchase Mariner common stock was converted into a fully vested option to purchase 0.24347 shares of Apache common stock.

Excluded from consideration was $4 million and approximately 100,000 shares of Apache common stock issued in exchange for 40 percent of Mariner employee performance-based restricted shares, which was recognized in merger, acquisitions and transition expense in the statement of consolidated operations.

The components of the consideration transferred follow:

		(In millions)
Cash consideration	$	787
Consideration attributable to stock issued(1)		1,896
Consideration attributable to converted stock options(2)		8
Total consideration transferred	$	2,691

(1) The fair value of Apache s common stock on the acquisition date was $110.25 per share based on the closing value on the NYSE. Apache issued 17.2 million shares of Apache common stock in exchange for Mariner common and restricted stock as part of consideration.

(2) On the effective date of the merger, Apache exchanged 145,438 stock options for options held by Mariner employees with a fair value of $8 million, determined using the Black-Scholes option pricing model.

Recording of Assets Acquired and Liabilities Assumed

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 preliminary estimates of the assets acquired and liabilities assumed in the merger. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained. These amounts will be finalized as soon as possible, but no later than one year from the acquisition date.

		(In millions)
Current assets	$	172
Property, plant and equipment		4,523

Goodwill(1)		843
Other assets		44
Total assets acquired	$	5,582
Current liabilities		158
Long-term debt(2)		1,656
Asset retirement obligation		537
Deferred income tax liabilities		509
Other long-term obligations		31
Total liabilities assumed	$	2,891
Net assets acquired	$	2,691

(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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

recognized. Goodwill is not amortized and is not deductible for tax purposes, but is subject to an impairment test annually and when other impairment conditions arise.

(2) Long-term debt was recognized based on market rates on the date of closing (Level 2). Long-term debt at closing was as follows:

Bank debt:		**(In millions)**
Revolving Credit Facility	$	632
Senior notes:		
7.5% due 2013 includes premium of $10 million		310
11.75% due 2016 includes premium of $81 million		381
8% due 2017 includes premium of $33 million		333
Total Long-term debt	$	1,656

Outstanding bank facility borrowings of $632 million were repaid immediately following closing through borrowings under Apache s commercial paper facility. During the fourth quarter of 2010, all remaining assumed debt was repaid with net proceeds from the issuance of new debt, as discussed further in Note 5 Debt, and with existing cash balances.

BP Acquisitions

In July 2010 Apache entered into three definitive purchase and sale agreements to acquire the properties described below from subsidiaries of BP plc (collectively referred to as BP) for aggregate consideration of $7.0 billion, subject to customary adjustments. The effective date of the transactions was July 1, 2010. Preferential purchase rights for approximately $658 million of the value of the BP properties in the Permian Basin were exercised, and accordingly, the purchase price for the BP properties was reduced to approximately $6.4 billion, subject to normal post-closing adjustments.

Permian Basin

On August 10, 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. The acquired assets, net of preferential purchase rights exercised, include interests in several field areas, including Block 16/Coy Waha, Brown Basset, Empire/Yeso, Pegasus, Southeast Lea, Spraberry, Wilshire, and Delaware Penn, approximately 405,000 net mineral and fee acres, approximately 351,000 leasehold acres and three gas processing plants. The Permian Basin assets had estimated net proved reserves of 124 MMboe (unaudited) (64 percent liquid hydrocarbons, or liquids) as of the effective date. The agreed-upon purchase price of $3.1 billion was reduced by $658 million for the exercise of preferential rights to purchase. Apache allocated $2.0 billion of the purchase price to proved property, $259 million to unproved property and $183 million to gas plant facilities. Apache also recorded abandonment obligations for the properties of $19 million and a reserve for environmental remediation of $11 million. BP continued to operate the properties on Apache s behalf through November 30, 2010.

Western Canada Sedimentary Basin

On October 8, 2010, Apache completed the acquisition of substantially all of BP s Western Canadian upstream natural gas assets, including approximately 1,278,000 net mineral and leasehold acres, interests in approximately 1,800 active wells and eight operated and 15 non-operated gas processing plants. The position includes many drilling opportunities ranging from conventional to several unconventional targets, such as shale gas, tight gas and coal bed methane in historically productive formations including the Montney, Cadomin and Doig. These properties had estimated net proved reserves of 224 MMboe (unaudited) (94 percent gas) as of the effective date. The purchase price was $3.25 billion, subject to normal post-closing adjustments. Apache allocated $2.7 billion of the purchase price to

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

proved property, $533 million to unproved property and $150 million to gas plant facilities. Apache also recorded abandonment obligations for the properties of $58 million and a reserve for environmental remediation of $98 million.

Western Desert, Egypt

On November 4, 2010, Apache completed the acquisition of BP s interests in four development licenses and one exploration concession (East Badr El Din) in the Western Desert of Egypt. These properties, covering 394,000 net acres south of El Alamein, are operated by Gulf of Suez Petroleum Company, a joint venture between BP and the Government of Egypt. The transaction includes BP s interests in 65 active wells, a 24-inch gas line, a liquefied petroleum gas plant in Dashour, a gas processing plant in Abu Gharadig and a portion of a 12-inch oil export line to the El Hamra Terminal on the Mediterranean Sea. These properties had estimated net proved reserves of 20 MMboe (unaudited) (59 percent liquids) as of the effective date. The merged concession agreement related to the development licenses runs through 2024, subject to a five-year extension at the option of the operator. The purchase price was $650 million, subject to normal post-closing adjustments. Apache allocated $325 million of the purchase price to proved property, $145 million to unproved property and $150 million to gas plant facilities.

The Company financed the purchase of properties from BP by issuing a combination of common stock and mandatory convertible preferred shares, raising net proceeds of $3.5 billion; securing a bridge loan facility; issuing new term debt and commercial paper; and using existing cash balances. For further discussion of these debt instruments and equity issuances, please see Note 5 Debt and Note 7 Capital Stock, respectively.

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, 2009:

	For the Year Ended December 31, 2010	2009
	(In millions, except per share amounts)	
Revenues and Other	$ 13,780	$ 10,717
Net Income (Loss)	$ 3,364	$ (477)
Preferred Stock Dividends	76	83
Income (Loss) Attributable to Common Stock	3,288	(560)

Net Income (Loss) per Common Share	Basic	$	8.62	$	(1.48)
Net Income (Loss) per Common Share	Diluted	$	8.52	$	(1.48)

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the acquisitions and merger and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company s consolidated results of operations actually would have been had the acquisitions and merger been completed on January 1, 2009. 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 depreciation, depletion and amortization expense, using the units-of-production method, resulting from the purchase of the properties;

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2010, Apache recorded $183 million of expenses in connection with the acquisition of properties from BP and the Mariner merger: $114 million of separation and other payroll 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. Management believes it is prudent to manage the variability in cash flows by entering into hedges 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. Derivative instruments entered into are typically designated as cash flow hedges.

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 institutions, for its derivative transactions. As of December 31, 2010, Apache had derivative positions with 20 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.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity Derivative Instruments

As of December 31, 2010, Apache had the following open crude oil derivative positions:

	Fixed-Price Swaps		Collars		
Production Period	Mbbls	Weighted Average Fixed Price(1)	Mbbls	Weighted Average Floor Price(1)	Weighted Average Ceiling Price(1)
2011	5,628	$ 73.36	30,110	$ 69.13	$ 96.59
2012	3,786	72.26	9,142	69.30	98.11
2013	1,860	74.38	2,416	78.02	103.06
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. A portion of 2011 contracts are settled against Dated Brent.

In the fourth quarter of 2010 Apache North Sea Ltd entered into a physical sales contract to deliver 20 thousand barrels of oil per day in 2011, settled against Dated Brent with a floor price of $70 and an average ceiling price of $98.56. These sales are in the normal course of business and will be recognized in oil and gas revenues on an accrual basis.

As of December 31, 2010, Apache had the following open natural gas derivative positions:

	Fixed-Price Swaps			Collars			
Production Period	MMBtu (in 000 s)	GJ (in 000 s)	Weighted Average Fixed Price(1)	MMBtu (in 000 s)	GJ (in 000 s)	Weighted Average Floor Price(1)	Weighted Average Ceiling Price(1)
2011	75,927		$ 6.00	9,125		$ 5.00	$ 8.85
2011		51,100	C$ 6.26		3,650	C$ 6.50	C$ 7.10
2012	41,554		$ 6.30	21,960		$ 5.54	$ 7.30
2012		43,920	C$ 6.61		7,320	C$ 6.50	C$ 7.27
2013	7,665		$ 6.83	6,825		$ 5.35	$ 6.67
2014	755		$ 7.23			$	$

(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 primarily against NYMEX Henry Hub and various Inside FERC

indices. The Canadian gas contracts are entered into on a per gigajoule (GJ) basis and are settled against AECO Index. The Canadian natural gas prices represent a weighted average of AECO Index prices and are shown in Canadian dollars.

Fair Values of Derivative Instruments Recorded in the Consolidated Balance Sheet

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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2010	December 31, 2009
	(In millions)	
Current Assets: Prepaid assets and other	$ 167	$ 13
Other Assets: Deferred charges and other	139	51
Total Assets	$ 306	$ 64
Current Liabilities: Derivative instruments	$ 194	$ 128
Noncurrent Liabilities: Other	124	202
Total Liabilities	$ 318	$ 330

The methods and assumptions used to estimate the fair values of the Company s commodity derivative instruments and gross amounts of commodity derivative assets and liabilities are more fully discussed in Note 9 Fair Value Measurements.

Commodity 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 Operations	For the Year Ended December 31, 2010	2009	2008
		(In millions)		
Gain (loss) reclassified from accumulated other comprehensive income (loss) into operations (effective portion)	Oil and Gas Production Revenues	$ 165	$ 181	$ (436)
Gain (loss) on derivatives recognized in operations (ineffective portion and basis swaps)	Revenues and Other: Other	$ (2)	$ (4)	$ 4

Commodity Derivative Activity in Accumulated Other Comprehensive Income (Loss)

As of December 31, 2010, 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:

	2010		2009		2008	
	Before tax	**After tax**	**Before tax**	**After tax**	**Before tax**	**After tax**
			(In millions)			
Unrealized gain (loss) on derivatives at beginning of year	$ (267)	$ (170)	$ 212	$ 138	$ (639)	$ (412)
Realized (gain) loss reclassified into earnings	(165)	(106)	(181)	(123)	436	282
Net change in derivative fair value	376	256	(297)	(184)	415	268
Ineffectiveness reclassified into earnings	2	1	(1)	(1)		
Unrealized gain (loss) on derivatives at end of year	$ (54)	$ (19)	$ (267)	$ (170)	$ 212	$ 138

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 applicable to specific hedges. Included in accumulated other comprehensive loss as of December 31, 2010 is a net loss of approximately $45 million ($24 million after tax)

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

4. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company s ARO liability for the years ended December 31, 2010 and 2009:

	2010	2009
	(In millions)	
Asset retirement obligation at beginning of year	$ 1,784	$ 1,895
Liabilities incurred	270	213
Liabilities acquired	847	5
Liabilities settled	(329)	(508)
Accretion expense	111	105
Revisions in estimated liabilities	189	74
Asset retirement obligation at end of year	2,872	1,784
Less current portion	(407)	(147)
Asset retirement obligation, long-term	$ 2,465	$ 1,637

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 2010, the Company recorded additional abandonment liabilities of $847 million related to the properties acquired in the BP, Devon and Mariner transactions. Apache also recorded additional abandonment liabilities of $270 million associated with its drilling and development program during the year.

Liabilities settled in 2010 relate to individual properties, platforms and facilities plugged and abandoned during the period. The Company has an active abandonment program with a majority of the activity in the Gulf of Mexico and Canada. In September 2010 the Bureau of Ocean Management, Regulation and Enforcement (BOEMRE, formerly known as the Minerals Management Service), a division of the U.S. Department of the Interior, issued Notice to Lessees (NTL) No. 2010-G05, which includes guidelines for decommissioning idle infrastructure on active leases in the Gulf of Mexico within a specified period of time. The Company has reviewed its Gulf of Mexico abandonment program in light of these new regulations and adjusted the timing of its abandonment program accordingly.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. DEBT

	December 31, 2010	December 31, 2009
	(In millions)	
U.S.:		
Money market lines of credit	$ 16	$
Unsecured committed bank credit facilities		
Commercial paper	913	
6.25% notes due 2012	400	400
5.25% notes due 2013	500	500
6.0% notes due 2013	400	400
5.625% notes due 2017	500	500
6.9% notes due 2018	400	400
7.0% notes due 2018	150	150
7.625% notes due 2019	150	150
3.625% notes due 2021	500	
7.7% notes due 2026	100	100
7.95% notes due 2026	180	180
6.0% notes due 2037	1,000	1,000
5.1% notes due 2040	1,500	
5.25% notes due 2042	500	
7.375% debentures due 2047	150	150
7.625% debentures due 2096	150	150
	7,509	4,080
Subsidiary and other obligations:		
Argentina overdraft lines of credit	30	7
Apache PVG secured facility		350
Notes due in 2016 and 2017	1	1
Apache Finance Canada 4.375% notes due 2015	350	350
Apache Finance Canada 7.75% notes due 2029	300	300
	681	1,008
Debt at face value	8,190	5,088
Unamortized discount	(49)	(21)
Total debt	8,141	5,067
Current maturities	(46)	(117)

Long-term debt	$ 8,095	$ 4,950

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt maturities as of December 31, 2010, excluding discounts, are as follows:

	(In millions)
2011	$ 46
2012	400
2013	1,813
2014	
2015	350
Thereafter	5,581
Total Debt, excluding discounts	$ 8,190

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 above 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.

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, 2010 and 2009, $46 million and $7 million, respectively, was drawn on facilities in the U.S. and Argentina.

Unsecured Committed Bank Credit Facilities

As of December 31, 2010, the Company had unsecured committed revolving syndicated bank credit facilities totaling $3.3 billion, of which $1.0 billion matures in August 2011 and $2.3 billion matures in May 2013. The facilities consist of a $1.0 billion 364-day facility, a $1.5 billion facility and a $450 million facility in the U.S., a $200 million facility in Australia and a $150 million facility in Canada. As of December 31, 2010, available borrowing capacity under the Company s credit facilities was $2.4 billion. The U.S. credit facilities are used to support Apache s commercial paper program.

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. The Company s debt-to-capitalization ratio at December 31, 2010 was 25 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 five percent of the Company s consolidated assets, or approximately $2.2 billion as of December 31, 2010. 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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $100 million or has any unpaid, non-appealable judgment against it in excess of $100 million.

The Company was in compliance with the terms of the credit facilities as of December 31, 2010.

At the Company s option, the interest rate for the facilities, excluding the 364-day facility discussed below, 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 $1.5 billion and the $450 million credit facilities also allow the Company to borrow under competitive auctions.

At December 31, 2010, the margin over LIBOR for committed loans was .19 percent on the $1.5 billion facility and .23 percent on the $450 million facility in the U.S., the $200 million facility in Australia and the $150 million facility in Canada. If the total amount of the loans borrowed under the $1.5 billion facility equals or exceeds 50 percent of the total facility commitments, then an additional .05 percent will be added to the margins over LIBOR. If the total amount of the loans borrowed under all of the other three facilities equals or exceeds 50 percent of the total facility commitments, then an additional .10 percent will be added to the margins over LIBOR. The Company also pays quarterly facility fees of .06 percent on the total amount of the $1.5 billion facility and .07 percent on the total amount of the other three facilities. The facility fees vary based upon the Company s senior long-term debt rating.

On August 13, 2010, Apache entered into a $1.0 billion 364-day syndicated revolving credit facility. The credit facility is subject to covenants, events of default and representations and warranties that are substantially similar to those in Apache s existing revolving credit facilities. It may be used for acquisitions and for general corporate purposes or to support the Company s commercial paper program.

The facility will terminate and all amounts outstanding will be due on August 12, 2011, unless Apache requests a 364-day extension, which is subject to lender approval, as defined, or Apache elects a one-year term out option. Loans under the facility will bear interest at a base rate, as defined, or at LIBOR plus a margin, which varies based upon prices reported in the credit default swap market with respect to Apache s one-year indebtedness and the rating for Apache s senior, unsecured long-term debt. Based upon prices for Apache s one-year credit default swaps and its current senior unsecured long-term debt rating, the margin at December 31, 2010, would be .75 percent. Apache must also pay a commitment fee on the undrawn portion of the facility which is based on its senior, unsecured long-term debt rating. The commitment fee is currently .125 percent.

Commercial Paper Program

In August 2010 the Company increased its commercial paper program from $1.95 billion to $2.95 billion. The commercial paper program generally enables Apache to borrow funds for up to 270 days at competitive interest rates. Apache s 2010 weighted-average interest rate for commercial paper was .37 percent. If the Company is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, the Company s U.S. credit facilities are available as a 100-percent backstop. The commercial paper program is fully supported by available borrowing capacity under U.S. committed credit facilities, which expire in 2011 and 2013. As of December 31, 2010, the Company had $913 million in commercial paper outstanding. There was no outstanding commercial paper at December 31, 2009.

Debt Issuances

On August 20, 2010, the Company issued $1.5 billion principal amount of senior unsecured 5.1-percent notes maturing September 1, 2040. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay borrowings under the Company s bridge facility and commercial paper program.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 3, 2010, the Company issued $500 million principal amount of senior unsecured 3.625-percent notes maturing February 1, 2021, and $500 million principal amount of senior unsecured 5.25-percent notes maturing February 1, 2042. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to redeem the outstanding public debt assumed upon completion of Apache s acquisition of Mariner Energy Inc. on November 10, 2010.

U.S. Debt

The U.S. 6.25-percent, 5.625-percent, 6.9-percent, 3.625-percent, 5.1-percent and both issues of 5.25-percent and 6.0-percent notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The remaining U.S. notes and debentures are not redeemable. Under certain conditions, the Company has the right to advance maturity on the U.S. 7.375-percent debentures due 2047 and 7.625-percent debentures due 2096.

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 14 Supplemental Guarantor Information.

Apache Deepwater Apache Deepwater assumed publicly traded debt upon consummation of its merger with Mariner. Mariner s publicly traded debt included $300 million of 7.5-percent senior notes due 2013, $300 million of 11.75-percent senior notes due 2016, and $300 million of 8-percent senior notes due 2017. On December 13, 2010, Apache Deepwater redeemed the 7.5-percent notes, the 8-percent notes, and 35 percent of the 11.75-percent notes pursuant to the provisions of each note s indenture. On December 14, 2010, Apache Deepwater redeemed the remaining 65 percent of the 11.75-percent notes.

Subsidiary Project Financing

In June 2010 one of the Company s Australian subsidiaries repaid $50 million under its amortizing secured revolving syndicated credit facility for its Van Gogh and Pyrenees oil developments offshore Western Australia. The remaining balance of $300 million was repaid in December 2010. Upon repayment of the remaining balance of the facility, all commitments under the facility were terminated and assets secured by the facility were released.

Financing Costs, Net

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

	For the Year Ended December 31,		
	2010	2009	2008
	(In millions)		

Interest expense	$ 345	$ 309	$ 280
Amortization of deferred loan costs	17	6	4
Capitalized interest	(120)	(61)	(94)
Interest income	(13)	(12)	(24)
Total Financing costs, net	$ 229	$ 242	$ 166

The Company has $49 million of debt discounts as of December 31, 2010, which will be charged to interest expense over the life of the related debt issuances. In connection with the 2010 debt issuances discussed above, Apache recorded $30 million in additional debt discounts. Discount amortization of $2 million, $1 million and $1 million were recorded as interest expense in 2010, 2009 and 2008, respectively.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2010 and 2009, the Company had approximately $53 million and $40 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.

6. INCOME TAXES

Income before income taxes is composed of the following:

	For the Year Ended December 31,		
	2010	2009	2008
		(In millions)	
United States	$ 1,328	$ (567)	$ (350)
Foreign	3,878	893	1,282
Total	$ 5,206	$ 326	$ 932

The total provision for income taxes consists of the following:

	For the Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Current taxes:			
Federal	$ 25	$ (130)	$ 128
State	4	(2)	1
Foreign	1,193	974	1,327
	1,222	842	1,456
Deferred taxes:			
Federal	431	(81)	(414)
State	7	(24)	3
Foreign	514	(126)	(825)
	952	(231)	(1,236)
Total	$ 2,174	$ 611	$ 220

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,		
	2010	2009	2008
	(In millions)		
Income tax expense at U.S. statutory rate	$ 1,822	$ 114	$ 326
State income tax, less federal benefit	6	(17)	3
Taxes related to foreign operations	245	310	430
Tax credits	(8)	(39)	
Non-deductible merger costs	6		
Current and deferred taxes related to currency fluctuations	111	195	(400)
Domestic manufacturing deduction			(7)
Net change in tax contingencies	(2)	36	(140)
Increase in valuation allowance	12	20	3
All other, net	(18)	(8)	5
	$ 2,174	$ 611	$ 220

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The net deferred tax liability consists of the following:

	December 31, 2010	December 31, 2009
	(In millions)	
Deferred tax assets:		
Deferred income	$ (6)	$ (20)
Federal and state net operating loss carryforwards	(277)	(35)
Foreign net operating loss carryforwards	(55)	(225)
Tax credits	(42)	(48)
Accrued expenses and liabilities	(76)	(105)
Other	(25)	(60)
Total deferred tax assets	(481)	(493)
Valuation allowance	53	35
Net deferred tax assets	(428)	(458)
Deferred tax liabilities:		
Depreciation, depletion and amortization	4,569	3,068
Total deferred tax liabilities	4,569	3,068
Net deferred income tax liability	$ 4,141	$ 2,610

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, 2010, the undistributed earnings of the foreign subsidiaries amounted to approximately $19.2 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, 2010, the Company had U.S. net operating losses of $656 million, state net operating loss carryforwards of $862 million and foreign net operating loss carryforwards of $59 million in Canada and $20 million in Argentina. The Company also had $234 million of capital loss carryforwards in Canada. The state net operating losses will expire over the next 20 years if they are not otherwise utilized. The foreign net operating loss in Canada will begin to expire in 2014, and the Argentina net operating loss will begin to expire in 2011. The capital loss in Canada has an indefinite carryover period.

The Company s federal net operating loss carryforward of $636 million is related to the merger with Mariner and is subject to annual limitations under Section 382 of the Internal Revenue Code.

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 Canadian capital losses and certain Argentina and U.S. state net operating losses to be more likely than not, a valuation allowance was provided to reduce the tax benefit from these deferred tax assets.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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:

	2010	2009	2008
		(In millions)	
Balance at beginning of year	$ 123	$ 213	$ 508
Additions based on tax positions related to the current year	(1)	23	
Additions for tax positions of prior years		77	48
Reductions for tax positions of prior years	(12)	(92)	(337)
Settlements		(98)	(6)
Balance at end of year	$ 110	$ 123	$ 213

Included in the balances at December 31, 2010 and 2009 are $14 million of tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than penalties and interest, the disallowance of the shorter deductibility period would not affect the annual effective income tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

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, 2010 and 2009, the Company recorded tax expense of $12 million and a benefit of $17 million, respectively. In 2008, the Company recorded a tax benefit of $87 million for interest and penalties. As of December 31, 2010 and 2009, the Company had approximately $36 million and $24 million, respectively, accrued for payment of interest and penalties.

The Company is in Administrative Appeals with the U.S. Internal Revenue Service (IRS) regarding the tax years 2004 through 2007. The Company is also under IRS audit for 2008 and under audit in various states and in most of the Company s foreign jurisdictions as part of its normal course of business. Resolution of any of the above, which may occur in 2011, could result in a significant change to the Company s tax reserves. However, 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. Due to this uncertainty and the uncertain timing of the final resolution of the Appeals process, an accurate estimate of the range of outcomes occurring during the next 12 months cannot be made at this time. Nevertheless, 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	
United States	2004
Canada	2006
Egypt	1998
Australia	2001
United Kingdom	2009
Argentina	2003

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. CAPITAL STOCK

Common Stock Outstanding

	2010	2009	2008
Balance, beginning of year	336,436,972	334,710,064	332,927,143
Shares issued for stock-based compensation plans:			
Treasury shares issued	363,263	404,232	350,895
Common shares issued	1,864,498	1,322,676	1,432,026
Equity offering (BP acquisitions)	26,450,000		
Mariner consideration	17,277,009		
Balance, end of year	382,391,742	336,436,972	334,710,064

Net Income (Loss) Per Common Share

A reconciliation of the components of basic and diluted net income (loss) per common share for the years ended December 31, 2010, 2009 and 2008 is presented in the table below. The loss for 2009 reflects an after-tax write-down for full-cost accounting of $1.98 billion. Income for 2008 reflects an after-tax write-down for full-cost accounting of $3.6 billion.

	2010			2009			2008		
	Income	Shares	Per Share	Loss	Shares	Per Share	Income	Shares	Per Share
	(In millions, except per share amounts)								
Basic:									
Income (loss) attributable to common stock	$ 3,000	352	$ 8.53	$ (292)	336	$ (.87)	$ 706	334	$ 2.11
Effect of Dilutive Securities:									
Mandatory Convertible Preferred Stock	$ 32	5		$			$		
Stock options and other		2						3	
Diluted:									
Income (loss) attributable to common	$ 3,032	359	$ 8.46	$ (292)	336	$ (.87)	$ 706	337	$ 2.09

stock, including
assumed conversions

The diluted earnings per share calculation excludes options and restricted shares that were anti-dilutive totaling 2.3 million, 4.2 million and .7 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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.

On November 10, 2010, in connection with the Mariner merger, Apache issued 17.3 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.

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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Common Stock Dividend

The Company paid common stock dividends of $.60, $.60 and $.70 per share in 2010, 2009 and 2008, respectively. The higher common stock dividends for 2008 were attributable to a special cash dividend of 10 cents per common share paid on March 18, 2008.

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. In May 2007, the Company s shareholders approved the 2007 Omnibus Equity Compensation Plan (the 2007 Plan), which is intended to provide eligible employees with equity-based incentives. The 2007 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. All new grants are issued from the 2007 Plan. The previous plans remain in effect solely for the purpose of governing grants still outstanding that were issued prior to approval of the 2007 Plan, including the 2005 Share Appreciation Plan, which remains in effect to issue shares for previously-attained stock appreciation goals.

For 2010, 2009 and 2008, stock-based compensation expensed was $164 million, $104 million and $52 million ($106 million, $67 million and $34 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:

	2010	2009	2008
		(In millions)	
Stock-based compensation expensed:			
General and administrative	$ 98	$ 67	$ 34
Lease operating expenses	66	37	18
Stock-based compensation capitalized	71	46	21
	$ 235	$ 150	$ 73

Stock Options

As of December 31, 2010, 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), and under the 2007 Plan discussed above. 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 used for employee stock option exercises to the extent treasury stock is held. Under the Stock Option Plans and the 2007 Plan, 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. All of these plans allow for accelerated vesting if there is a change in control, as defined in each plan. The 2007 Plan and all of the Stock Option

Plans, except for the 2000 Stock Option Plan, were submitted to and approved by the Company s shareholders.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of stock options issued and outstanding under the Stock Option Plans and the 2007 Plan is presented in the table and narrative below (shares in thousands):

	2010	
	Shares Under Option (In thousands)	Weighted Average Exercise Price
Outstanding, beginning of year	5,920	$ 72.29
Granted	1,213	99.30
Mariner options converted to Apache options	145	57.42
Exercised	(1,266)	57.34
Forfeited or expired	(151)	89.44
Outstanding, end of year(1)	5,861	80.30
Expected to vest(1)	2,119	91.84
Exercisable, end of year(1)	3,248	70.62
Available for grant, end of year	1,970	
Weighted average fair value of options granted during the year	$ 34.12	

(1) As of December 31, 2010, the weighted average remaining contractual life for options outstanding, expected to vest, and exercisable is 6.6 years, 8.3 years and 5.2 years, respectively. The aggregate intrinsic value of options outstanding, expected to vest and exercisable at year-end was $233 million, $60 million and $161 million, respectively. The weighted-average grant-date fair value of options granted during the years 2010, 2009 and 2008 was $34.12, $29.71 and $39.76, 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.

	2010	2009	2008

Expected volatility	35.02%	38.73%	27.93%
Expected dividend yields	.60%	.73%	.53%
Expected term (in years)	5.5	5.5	5.5
Risk-free rate	2.31%	2.06%	3.04%

The intrinsic value of options exercised during 2010, 2009 and 2008 was approximately $62 million, $39 million and $100 million, respectively. The cash received from exercise of options during 2010 was approximately $73 million. The Company realized an additional tax benefit of approximately $14 million for the amount of intrinsic value in excess of compensation cost recognized in 2010. As of December 31, 2010, the total compensation cost related to non-vested options not yet recognized was $62 million, which will be recognized over the remaining vesting period of the options.

Stock Appreciation Rights

In 2003 and 2004, respectively, the Company issued a total of 1,809,060 and 1,334,300 of stock appreciation rights (SARs) to non-executive employees in lieu of stock options. The SARs vested ratably over four years and are

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

settled in cash upon exercise throughout their 10-year life. The weighted-average exercise price was $42.68 and $28.78 for those issued in 2004 and 2003, respectively. The number of SARs outstanding and exercisable as of December 31, 2010 was 595,786. 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 $84.29 based on the Black-Scholes valuation methodology using assumptions comparable to those discussed above. During 2010, 181,697 SARs were exercised. The aggregate of cash payments made to settle SARs was $13 million.

Restricted Stock and Restricted Stock Units

The Company has restricted stock and restricted stock unit plans, including those awarded pursuant to programs under the 2007 Plan, for eligible employees including officers. The programs created under the 2007 Plan have been approved by Apache s Board of Directors. In 2010 the Company awarded 1,143,989 restricted stock units at a weighted-average per-share market price of $103.88. In 2009 and 2008 the Company awarded 1,119,936 and 787,846 restricted stock units at a weighted-average per-share market price of $84.30 and $136.05, 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 2010, 2009 and 2008, $73 million ($47 million after tax), $37 million ($24 million after tax) and $20 million ($13 million after tax), respectively, was charged to expense. In 2010, 2009 and 2008, $28 million, $12 million and $6 million was capitalized, respectively. As of December 31, 2010, there was $160 million of total unrecognized compensation cost related to 2,209,722 unvested restricted stock units. The weighted-average remaining life of unvested restricted stock units is approximately 1.3 years.

The fair value of the awards vesting during 2010, 2009 and 2008 was approximately $69 million, $34 million and $15 million, respectively. A summary of restricted stock activity for the year ended December 31, 2010 is presented below.

Restricted Stock	**Shares**	**Weighted-Average Grant-Date Fair Value**
	(In thousands)	
Non-vested at January 1, 2010	1,835	$ 98.95
Granted	1,144	103.88
Vested	(686)	101.27
Forfeited	(83)	100.46
Non-vested at December 31, 2010	2,210	100.72

Conditional Restricted Stock Units

To provide long-term incentives for Apache employees to deliver competitive returns to the Company s stockholders, in January 2010 the Company s Board of Directors approved the 2010 Performance Program, pursuant to the 2007

Plan. Eligible employees received initial conditional restricted stock unit awards totaling 541,465 units. A total of 523,240 units were outstanding at December 31, 2010, from which a minimum of zero and a maximum of 1,353,663 units could be awarded 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.

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 2010, $7 million ($4 million after tax) was charged to expense and $3 million was capitalized. As of December 31, 2010, there was $65 million of total unrecognized compensation

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cost related to 523,240 unvested conditional restricted stock units. The weighted-average remaining life of the unvested conditional restricted stock units is approximately 2.8 years.

Conditional Restricted Stock Award	Shares (In thousands)	Weighted-Average Grant-Date Fair Value(1)
Non-vested at January 1, 2010		$
Granted	541	141.86
Forfeited	(18)	141.86
Non-vested at December 31, 2010	523	141.86

(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 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 2011 the Company s Board of Directors approved the 2011 Performance Program, pursuant to the 2007 Plan, with terms similar to the 2010 Performance Program. Eligible employees received initial conditional restricted stock unit awards totaling 585,715 units, with the ultimate number of restricted stock units to be awarded ranging from zero to a maximum of 1,464,288 units.

Share Appreciation Plans

The Company has 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. Awards under the plans are payable in equal annual installments as specified by each plan, beginning on a date not more than 30 days after a threshold is attained for the required measurement period and on succeeding anniversaries of the attainment date. Shares issued to employees are reduced by the required minimum tax withholding. 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 Company s 2007 Omnibus Equity Compensation 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. Any awards under the program would be payable in five equal annual installments. The interim target of $162 was not met by the end of 2010, and the related awards were cancelled. The $216 share price target has not been met.

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. Awards under the plan are payable in four equal annual installments to eligible employees remaining with the Company. Apache s share price exceeded the interim $81 threshold for the 10-day requirement as of June 14, 2007, and the first and second installments were awarded in July 2007 and 2008. The third and fourth installments were awarded in June 2009 and 2010. Apache s share price exceeded the $108 threshold for the 10-day requirement as of February 29, 2008. The first three installments were awarded in March 2008, 2009 and 2010, and the fourth installment will be awarded in March 2011.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the number of shares contingently issuable as of December 31, 2010, 2009 and 2008 for each plan is presented in the table below:

	Shares Subject to Conditional Grants		
	2010	2009	2008
		(In thousands)	
2008 Share Appreciation Program			
Outstanding, beginning of year	2,592	2,814	
Granted	25	93	2,929
Forfeited or cancelled	(1,132)	(315)	(115)
Outstanding, end of year(1)	1,485	2,592	2,814
Weighted-average fair value of grants outstanding(2)	$ 71.16	$ 79.61	$ 81.73
2005 Share Appreciation Plan			
Outstanding, beginning of year	1,103	2,001	2,945
Issued(3)	(678)	(815)	(805)
Forfeited or cancelled	(25)	(83)	(139)
Outstanding, end of year	400	1,103	2,001
Weighted-average fair value of grants outstanding(4)	$ 21.64	$ 24.29	$ 24.98

(1) Represents shares issuable upon target achievement and vesting of awards related to the $216 and $162 per share price goals of 1,485,210 and zero shares, respectively, at December 31, 2010; 1,556,160 and 1,035,640 shares, respectively, at December 31, 2009; and 1,685,430 and 1,128,320 shares, respectively, at December 31, 2008.

(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 2010, 2009 and 2008 was approximately $18 million, $21 million and $21 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.

Current accounting practices dictate that the Company recognize, 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 interim price target of the 2008 Share Appreciation Program was not met prior to the stated achievement period, December 31, 2010, Apache recognized $27 million of unamortized expense and $14 million of unamortized capital costs. The Company will recognize total expense and capitalized costs for the 2008 Share Appreciation Program and the 2005 Share Appreciation Plan over the expected service life of each program: approximately $195 million through 2014 for the 2008 Share Appreciation Program and $79 million through 2011

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for the 2005 Share Appreciation Plan. 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,		
	2010	2009	2008
	(In millions)		
2008 Share Appreciation Program			
Compensation expense	$ 49	$ 23	$ 15
Compensation expense, net of tax	31	15	10
Capitalized costs	27	13	8
2005 Share Appreciation Plan			
Compensation expense	$ 6	$ 6	$ 9
Compensation expense, net of tax	4	4	6
Capitalized costs	3	3	5

Preferred Stock

The Company has 5,000,000 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). The Company redeemed the 100,000 outstanding shares of its 5.68 percent Series B Cumulative Preferred Stock (the Series B Preferred Stock) on December 30, 2009.

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, 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.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Series B Preferred Stock

In August 1998, Apache issued 100,000 shares ($100 million) of Series B Preferred Stock in the form of one million depositary shares, each representing one-tenth (1/10) of a share of Series B Preferred Stock, for net proceeds of $98 million. On December 30, 2009, Apache redeemed all Series B Preferred Stock at $1,000 per preferred share plus $9.47 in accrued and unpaid dividends. Holders of the shares were entitled to receive cumulative cash dividends at an annual rate of $5.68 per depositary share. During 2009 and 2008 Apache accrued a total of $6 million each year in dividends on its Series B Preferred Stock issued in August 1998. As the final dividend payment was accelerated with the redemption of the Series B Preferred Stock, Apache paid $7 million in dividends on this stock during 2009, compared to $6 million during 2008. These preferred shares were redeemed on December 30, 2009.

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 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 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.

<u>Accumulated Other Comprehensive Income (Loss)</u>

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

	For the Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Currency translation adjustment(1)	$ (109)	$ (109)	$ (109)
Unrealized gain (loss) on derivatives (Note 3)	(19)	(170)	138
Unfunded pension and postretirement benefit plan	(13)	(11)	(7)

Accumulated other comprehensive income (loss)	$ (141)	$ (290)	$ 22

(1) Prior to October 1, 2002, the Company s Canadian subsidiaries functional currency was the Canadian dollar. Translation adjustments resulting from translating the Canadian subsidiaries financial statements into U.S. dollar equivalents were reported separately and accumulated in other comprehensive income (loss). Currency translation adjustments held in other comprehensive income (loss) on the balance sheet will remain there indefinitely unless there is a substantially complete liquidation of the Company s Canadian operations.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $14 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 or results of operations after consideration of recorded accruals. 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 or results of operations.

Argentine Environmental Claims

In connection with the acquisition from 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 suit 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, 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. While the plaintiffs will seek to make all oil and gas companies operating in the Neuquén basin jointly liable for each other s actions, PNRA will defend on an individual basis and attempt to require the plaintiffs to delineate damages by company. PNRA intends to defend itself vigorously in the case. It is not certain exactly what the court will do in this matter as it is the first of its kind. While it is possible PNRA may incur liabilities related to the environmental claims, no reasonable prediction can be made as PNRA s exposure related to this lawsuit is not currently determinable.

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. Many of these lawsuits claim small amounts, while others assert claims in excess of $1 million. Also, some lawsuits or claims are being settled or resolved, while others are still being filed. Any exposure, therefore, 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

In a case styled Ned Comer, et al vs. Murphy Oil USA, Inc., et al, Case No: 1:05-cv-00436; U.S.D.C., United States District Court, Southern District of Mississippi, Mississippi property owners allege that hurricanes meteorological effects increased in frequency and intensity due to global warming, and there will be continued

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

future damage from increasing intensity of storms and sea level rises. They claim this was caused by the various defendants (oil and gas companies, electric and coal companies, and chemical manufacturers). Plaintiffs claim defendants emissions of greenhouse gases cause global warming, which they blame as the cause of their damages. They also claim that the oil company defendants artificially inflated and manipulated the prices of gasoline, diesel fuel, jet fuel, natural gas, and other end-use petrochemicals, and covered it up by misrepresentations. They further allege a conspiracy to disseminate misinformation and cover up the relationship between the defendants and global warming. Plaintiffs seek, among other damages, actual, consequential, and punitive or exemplary damages. The District Court dismissed the case on August 30, 2007. The plaintiffs appealed the dismissal. Prior to the dismissal, the plaintiffs filed a motion to amend the lawsuit to add additional defendants, including Apache. On October 16, 2009, the United States Court of Appeals for the Fifth Circuit reversed the judgment of the District Court and remanded the case to the District Court. The Fifth Circuit held that plaintiffs have pleaded sufficient facts to demonstrate standing for their public and private nuisance, trespass, and negligence claims, and that those claims are justifiable and do not present a political question. However, the Fifth Circuit declined to find standing for the unjust enrichment, civil conspiracy, and fraudulent misrepresentation claims, and therefore dismissed those claims. Several defendants filed a petition with the Fifth Circuit for a rehearing *en banc*. In granting an appeal for an *en banc* hearing, the U.S. Fifth Circuit Court of Appeals vacated an earlier ruling by its three-member panel. That decision reinstated the district judge s dismissal of the lawsuit. Subsequently, the Fifth Circuit Court of Appeals could not form a quorum to hear the *en banc* appeal. Therefore, the court ruled that its earlier order (vacating the panel s ruling) stood, which had the effect of dismissing the original lawsuit. The U.S. Supreme Court has denied plaintiffs petition for a writ of mandamus.

Australia Gas Pipeline Force Majeure

The 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 have 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. Other customers have threatened to file suit challenging the declaration of force majeure under their contracts. Contract prices under their 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. In their Harris County petition, 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 GSA, interest and court costs. 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 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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

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. NOPSA states in its report that an application for renewal of 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 license was submitted to DoIR by Company subsidiaries in December 2005 and remains pending.

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 its Department of Mines and Petroleum (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. Their report has been delivered to the Minister for Mines and Petroleum, but neither the report nor its contents have been made available to Company subsidiaries for their review and comment.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On May 28, 2009, the 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 plans to vigorously pursue its defenses.

Mariner Stockholder Lawsuits

In connection with the Merger, two shareholder lawsuits styled as class actions have been filed against Mariner and its board of directors. The lawsuits are entitled *City of Livonia Employees Retirement System, Individually and on Behalf of All Others Similarly Situated vs. Mariner Energy, Inc, et al.,* (filed April 16, 2010, in the District Court of Harris County, Texas), and *Southeastern Pennsylvania Transportation Authority, individually, and on behalf of all those similarly situated*, *vs. Scott D. Josey, et.al.,* (filed April 21, 2010, in the Court of Chancery in the State of Delaware). The Southeastern Pennsylvania Transportation Authority lawsuit also names Apache and its wholly owned subsidiary, ZMZ Acquisitions LLC (the Merger Sub) as defendants. The complaints generally allege that (1) Mariner s directors breached their fiduciary duties in negotiating and approving the Merger and by administering a sale process that failed to maximize shareholder value and (2) Mariner, and in the case of the Southeastern Pennsylvania Transportation Authority complaint, Apache and the Merger Sub, aided and abetted Mariner s directors in breaching their fiduciary duties. The City of Livonia Employees Retirement System complaint also alleges that Mariner s directors and executives stand to receive substantial financial benefits from the transaction. Pending court approval, these lawsuits have been settled in principle and are not expected to have a material impact on Apache.

Escheat Audits

The State of Delaware, Department of Finance, Division of Revenue (Unclaimed Property), has notified numerous companies, including Apache Corporation, that the State intends to examine its books and records and those of its subsidiaries and related entities to determine compliance with the Delaware Escheat Laws. The review will be 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.

NAL GP Ltd Lawsuit

In a lawsuit commenced on September 23, 2010, and styled as NAL GP Ltd., Applicant, and BP Canada Energy Company, BP Canada Energy, and Apache Corporation, Respondents, Action No. 1001-14115, in the Court of Queen s Bench of Alberta, Judicial District of Calgary, NAL GP Ltd. (NAL) seeks, among other things, interim injunctive relief to freeze the 15-day notice period concerning NAL s rights of first refusal relating to certain of the Canadian assets involved in the transaction between BP and Apache announced July 20, 2010, and further a hearing concerning the allocated values associated with such assets (approximately $1.6 billion USD in the aggregate). Apache Corporation was wrongly named as a respondent in the proceeding, and so Apache Canada Ltd. has appeared in the proceeding. A hearing on NAL s application was held on September 27, 2010. On September 28, 2010, the Court dismissed NAL s application in its entirety. NAL filed an appeal. The parties have resolved the matter amicably, including the dismissal of the lawsuit and discontinuance of the appeal, which resolution did not have a material effect on the Company.

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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 to 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.

As of December 31, 2010, the Company had an undiscounted reserve for environmental remediation of approximately $135 million, of which approximately $109 million is related to properties acquired in 2010. Apache is not aware of any environmental claims existing as of December 31, 2010 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. has 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 dispute centers 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. Apache Canada Ltd. is diligently pursuing this claim.

Retirement and Deferred Compensation Plans

Apache Corporation provides retirement benefits to its U.S. employees through the use of three types of plans: an Internal Revenue Code (IRC) 401(k) savings plan, a money purchase retirement plan and a restorative non-qualified retirement savings plan. The 401(k) savings plan provides participating employees the ability to elect to contribute up to 50 percent of eligible compensation to the plan with the Company making matching contributions up to a maximum of six percent of each employee s annual covered compensation. In addition, the Company annually contributes six percent of each participating employee s compensation, as defined, to a money purchase retirement plan. The 401(k) 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 that allows the deferral of up to 50 percent of each employee s salary and 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 and the non-qualified retirement/savings plan occurs at the rate of 20 percent for every full year of employment. Upon a change in control of ownership, immediate and full vesting occurs.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 United Kingdom, respectively.

The aggregate annual cost of the 401(k) savings plans, the money purchase retirement plan and the non-qualified retirement/savings plans was $80 million, $66 million and $52 million for 2010, 2009 and 2008, 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 United Kingdom (U.K.). The plan provides defined pension benefits based on years of service and final average 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. Covered participants receive medical benefits up until the age of 65 or the Medicare eligibility date, if later, 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.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

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, 2010, 2009 and 2008, 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.

	2010		2009		2008	
	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	$ 135	$ 18	$ 99	$ 17	$ 130	$ 14
Service cost	5	2	4	2	6	2
Interest cost	7	1	6	1	7	1
Foreign currency exchange rate changes	(4)		13		(38)	
Amendments						
Actuarial losses (gains)	(1)	8	17	(1)	(2)	
Effect of curtailment and settlements						
Benefits paid	(6)		(4)	(1)	(4)	
Retiree contributions						
Projected benefit obligation at end of year	136	29	135	18	99	17
Change in Plan Assets						
Fair value of plan assets at beginning of year	118		83		122	
Actual return on plan assets	14		12		(13)	
Foreign currency exchange rates	(3)		11		(32)	
Employer contributions	12		16	1	10	
Benefits paid	(6)		(4)	(1)	(4)	
Retiree contributions						
Fair value of plan assets at end of year	135		118		83	
Funded status at end of year	$ (1)	$ (29)	$ (17)	$ (18)	$ (17)	$ (17)
Amounts recognized in Consolidated Balance Sheet						

Current liability		(1)		(1)		
Non-current liability	(1)	(28)	(17)	(17)	(17)	(17)
	$ (1)	$ (29)	$ (17)	$ (18)	$ (17)	$ (17)
Pretax Amounts Recognized in Accumulated Other Comprehensive Income						
Accumulated gain (loss)	(15)	(8)	(24)		(14)	
Prior service cost						
Transition asset (obligation)						
	$ (15)	$ (8)	$ (24)	$	$ (14)	$
Weighted Average Assumptions used as of December 31						
Discount rate	5.40%	4.93%	5.70%	5.56%	5.50%	6.03%
Salary increases	5.00%	N/A	5.30%	N/A	4.50%	N/A
Expected return on assets	6.25%	N/A	6.65%	N/A	6.05%	N/A
Healthcare cost trend						
Initial	N/A	8.00%	N/A	7.50%	N/A	8.00%
Ultimate in 2015	N/A	5.00%	N/A	5.00%	N/A	5.00%

As of December 31, 2010, 2009 and 2008, the accumulated benefit obligation for the pension plan was $107 million, $89 million and $69 million, respectively.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 holding and the target allocation for the Company s plan assets are summarized below:

	Target Allocation 2010	Percentage of Plan Assets at Year-End 2010	2009
Asset Category			
Equity securities:			
U.K. quoted equities	17%	18%	28%
Overseas quoted equities	33%	34%	19%
Total equity securities	50%	52%	47%
Debt securities:			
U.K. Government bonds	36%	31%	31%
U.K. corporate bonds	14%	17%	18%
Debt securities	50%	48%	49%
Cash			4%
Total	100%	100%	100%

The plan s assets do not include any 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 9 Fair Value Measurements. 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, 2010:

	Fair Value Measurements Using: Quoted Price in Active	Significant	Unobservable

	Markets (Level 1)	Other Inputs (Level 2)	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)	42			42
U.K. corporate bonds(4)	23			23
Total debt securities	65			65
Cash				
Fair value of plan assets	$ 135	$	$	$ 135

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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.

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, 2009:

	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)	$ 34	$	$	$ 34
Overseas quoted equities(2)	22			22
Total equity securities	56			56
Debt securities:				
U.K. Government bonds(3)	36			36
U.K. corporate bonds(4)	21			21
Total debt securities	57			57
Cash	5			5

Fair value of plan assets	$	118	$		$		$	118

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

(2) This category includes overseas equities: 40 percent benchmarked against the FTSE Europe ex UK Index; 30 percent against the FTSE North America Index; 20 percent against the FTSE Japan Index; and 10 percent against the FTSE Asia Pacific ex Japan Index.

(3) This category includes U.K. Government bonds: 67 percent benchmarked against the FTSE A British Government Over 15 Years Index; 16.5 percent against the FTSE Actuaries Government Securities Over 15 Years Gilt Index; and 16.5 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 £ Non Gilt Over 10 Years 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.

Table of Contents

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, 2010, 2009 and 2008:

	2010		2009		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
			(In millions)			
Components of Net Periodic Benefit Costs						
Service cost	$ 5	$ 2	$ 4	$ 2	$ 6	$ 2
Interest cost	7	1	6	1	7	1
Expected return on assets	(8)		(6)		(8)	
Amortization of:						
Transition obligation						
Actuarial (gain) loss	1					
Net periodic benefit cost	$ 5	$ 3	$ 4	$ 3	$ 5	$ 3
Weighted Average Assumptions used to determine Net Periodic Benefit Costs for the Years ended December 31						
Discount rate	5.7%	5.56%	5.50%	6.03%	5.60%	6.01%
Salary increases	5.3%	N/A	4.50%	N/A	4.40%	N/A
Expected return on assets	6.65%	N/A	6.05%	N/A	6.50%	N/A
Healthcare cost trend						
Initial		7.50%		8.00%		8.00%
Ultimate in 2014		5.00%		5.00%		5.00%

Assumed health care cost trend rates effect 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	$	$
Effect on postretirement benefit obligation	3	(3)

Apache expects to contribute approximately $11 million to its pension plan and $546,000 to its postretirement benefit plan in 2011. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Postretirement Benefits
	(In millions)	
2011	4	1
2012	3	1
2013	5	2
2014	6	2
2015	6	2
Years 2016 2020	39	18

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contractual Obligations

At December 31, 2010, contractual obligations for drilling rigs, purchase obligations, exploration and development (E&D) commitments, firm transportation agreements, and long-term operating leases ranging from one to 26 years, are as follows:

Net Minimum Commitments	Total	2011	2012-2014	2015-2016	2017 & Beyond
			(In millions)		
Drilling rig commitments(1)	$ 392	$ 303	$ 89	$	$
Purchase obligations(2)	833	574	259		
E&D commitments(3)	575	235	308	32	
Firm transportation agreements(4)	809	138	423	170	78
Office and related equipment(5)	166	34	70	25	37
Oil and gas operations equipment(6)	476	85	146	55	190
Other	5	5			
Total Net Minimum Commitments	$ 3,256	$ 1,374	$ 1,295	$ 282	$ 305

(1) Includes day-rate and other contracts for use of drilling, completion and workover rigs.

(2) Include contractual obligations to buy or build oil and gas plants and facilities.

(3) Generally consists of seismic and drilling work programs required to retain acreage, meet contractual obligations of international concessions, or to satisfy minimum investments associated with farm-in properties.

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

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

(6) Includes floating production storage and offloading (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 $46 million, $38 million and $38 million for 2010, 2009 and 2008, respectively.

9. FAIR VALUE MEASUREMENTS

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 techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and 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).

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis in Apache s consolidated balance sheet. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Short-Term Investments, Accounts Receivable and Accounts Payable

The carrying amounts approximate fair value because of the short-term nature or maturity of the instruments.

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. For further information regarding Apache s derivative instruments and hedging activities, please see Note 3 Derivative Instruments and Hedging Activities.

The following table presents the Company s material assets and liabilities measured at fair value on a recurring basis for each hierarchy level:

	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, 2010						
Assets:						
Commodity Derivative Instruments	$	$ 454	$	$ 454	$ (148)	$ 306
Liabilities:						
Commodity Derivative Instruments		466		466	(148)	318
December 31, 2009						
Assets:						
Commodity Derivative Instruments	$	$ 75	$	$ 75	$ (11)	$ 64
Liabilities:						
Commodity Derivative Instruments		341		341	(11)	330

(1) The derivative fair values above are based on analysis of each contract as required by ASC Topic 820. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. For a discussion of net amounts recorded on the consolidated balance sheet at December 31, 2010 and 2009, please see Note 3 Derivative Instruments and Hedging Activities.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Apache s consolidated balance sheet. The following methods and assumptions were used to estimate fair values:

Asset Retirement Obligations Incurred in Current Period

Apache uses an income approach to estimate the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. AROs incurred in the current period were Level 3 fair value measurements. A summary of changes in the ARO liability is provided in Note 4 Asset Retirement Obligation.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt

The Company s debt is recorded at the carrying amount on its consolidated balance sheet. For further discussion of the Company s debt, please see Note 5 Debt. 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. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. The following table presents the carrying amounts and estimated fair values of the Company s debt at December 31, 2010 and 2009:

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Money market lines of credit	$ 46	$ 46	$ 7	$ 7
Commercial paper	913	913		
Notes and debentures	7,182	7,870	5,060	5,628

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. The Company s trade payables and short-term investments are, by their very nature, short-term. The carrying values of these items included in the accompanying consolidated balance sheet approximate fair value at December 31, 2010 and 2009.

10. MAJOR CUSTOMERS

In 2010, 2009 and 2008, purchases by Shell accounted for 15 percent, 18 percent and 17 percent, respectively, of the Company s worldwide oil and gas production revenues.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. 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, 2010, the Company had production in six countries: the United States, Canada, Egypt, Australia, offshore the U.K. in the North Sea and Argentina. Apache also has exploration interest on the Chilean side of the island of Tierra del Fuego. Financial information for each country is presented below:

	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
Additional								
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 (Loss)(1)	$ 1,919	$ 313	$ 2,279	$ 846	$ 672	$ 60	$	6,089
Other Income (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	$ 43,425
Additions to Net Property and Equipment	$ 10,371	$ 5,277	$ 1,569	$ 925	$ 620	$ 274	$ 20	$ 19,056
2009								
Oil and gas production revenues	$ 3,050	$ 877	$ 2,553	$ 363	$ 1,369	$ 362	$	$ 8,574
Operating Expenses:								
Depreciation, depletion and amortization								
Recurring	947	257	578	204	260	149		2,395
Additional	1,222	1,596						2,818
Asset retirement obligation accretion	63	19		6	14	3		105
Lease operating expenses	762	269	264	101	158	108		1,662
Gathering and transportation	36	53	23		26	5		143
Taxes other than income	121	43	9	10	383	14		580
Operating Income (Loss)(1)	$ (101)	$ (1,360)	$ 1,679	$ 42	$ 528	$ 83	$	871
Other Income (Expense):								
Other								41
General and administrative								(344)
Financing costs, net								(242)
Income Before Income Taxes								$ 326
Net Property and Equipment	$ 9,859	$ 3,251	$ 3,910	$ 2,965	$ 1,655	$ 1,223	$ 38	$ 22,901
Total Assets	$ 11,526	$ 3,776	$ 5,626	$ 3,346	$ 2,444	$ 1,428	$ 40	$ 28,186
Additions to Net Property and Equipment	$ 1,342	$ 604	$ 873	$ 774	$ 379	$ 171	$ 11	$ 4,154

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Canada	Egypt	Australia	North Sea	Argentina	Other International	Total
				(In millions)				
2008								
Oil and gas production revenues	$ 5,083	$ 1,651	$ 2,739	$ 372	$ 2,103	$ 380	$	$ 12,328
Operating Expenses:								
Depreciation, depletion and amortization								
Recurring	1,113	417	397	135	263	191		2,516
Additional	2,667	1,689			569	409		5,334
Asset retirement obligation accretion	66	14		6	13	2		101
Lease operating expenses	926	337	241	104	191	111		1,910
Gathering and transportation	40	63	21		28	5		157
Taxes other than income	212	43	8	11	695	16		985
Operating Income (Loss)(1)	$ 59	$ (912)	$ 2,072	$ 116	$ 344	$ (354)	$	1,325
Other Income (Expense):								
Other								62
General and administrative								(289)
Financing costs, net								(166)
Income Before Income Taxes								$ 932
Net Property and Equipment	$ 10,686	$ 4,500	$ 3,615	$ 2,394	$ 1,536	$ 1,200	$ 28	$ 23,959
Total Assets	$ 11,976	$ 5,846	$ 4,968	$ 2,626	$ 2,287	$ 1,446	$ 37	$ 29,186
Additions to Net Property and Equipment	$ 2,748	$ 872	$ 1,452	$ 938	$ 479	$ 363	$ 27	$ 6,879

(1) Operating Income consists of oil and gas production revenues less depreciation, depletion and amortization, asset retirement obligation accretion, lease operating expenses, gathering and transportation costs, and taxes other than income.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

Oil and Gas Operations

The following table sets forth revenue and direct cost information relating to the Company s oil and gas exploration and production activities. Apache has no long-term agreements to purchase oil or gas production from foreign governments or authorities.

	United States	Canada	Egypt	Australia	North Sea	Argentina	Other International	Total
	(In millions, except per boe)							
2010								
Oil and gas production revenues	$ 4,300	$ 1,074	$ 3,372	$ 1,459	$ 1,606	$ 372	$	$ 12,183
Operating cost:								
Depreciation, depletion and amortization								
Recurring(1)	1,126	287	754	403	301	157		3,028
Additional								
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
Production taxes(2)	177	31		11	423	14		656
Income tax	699	82	1,099	255	337	25		2,497
	3,030	832	2,182	863	1,269	326		8,502
Results of operations	$ 1,270	$ 242	$ 1,190	$ 596	$ 337	$ 46	$	$ 3,681
Amortization rate per boe	$ 13.23	$ 8.13	$ 11.05	$ 13.38	$ 14.42	$ 9.56	$	$ 11.92
2009								
Oil and gas production revenues	$ 3,050	$ 877	$ 2,553	$ 363	$ 1,369	$ 362	$	$ 8,574
Operating cost:								
Depreciation, depletion and amortization								

Recurring(1)	915	250	578	202	256	147		2,348
Additional	1,222	1,596						2,818
Asset retirement obligation accretion	63	19		6	14	3		105
Lease operating expenses	762	269	264	101	158	108		1,662
Gathering and transportation	36	53	23		26	5		143
Production taxes(2)	107	35		10	383	7		542
Income tax	(19)	(336)	810	14	266	32		767
	3,086	1,886	1,675	333	1,103	302		8,385
Results of operations	$ (36)	$ (1,009)	$ 878	$ 30	$ 266	$ 60	$	$ 189
Amortization rate per boe	$ 12.10	$ 7.58	$ 8.86	$ 12.61	$ 11.40	$ 8.62	$	$ 10.34
2008								
Oil and gas production revenues	$ 5,083	$ 1,651	$ 2,739	$ 372	$ 2,103	$ 380	$	$ 12,328
Operating cost:								
Depreciation, depletion and amortization								
Recurring(1)	1,081	410	398	133	261	188		2,471
Additional	2,667	1,689			569	409		5,334
Asset retirement obligation accretion	66	14		6	13	2		101
Lease operating expenses	926	337	241	104	191	111		1,910
Gathering and transportation	40	63	21		28	5		157
Production taxes(2)	201	34		11	695			941
Income tax	37	(215)	998	35	173	(118)		910
	5,018	2,332	1,658	289	1,930	597		11,824
Results of operations	$ 65	$ (681)	$ 1,081	$ 83	$ 173	$ (217)	$	$ 504
Amortization rate per boe	$ 14.08	$ 13.11	$ 8.48	$ 11.26	$ 11.89	$ 10.49	$	$ 12.06

(1) This amount only reflects DD&A of capitalized costs of oil and gas proved properties and, therefore, does not agree with DD&A reflected on Note 11 Business Segment Information.

(2) This amount only reflects amounts directly related to oil and gas producing properties and, therefore, does not agree with taxes other than income reflected on Note 11 Business Segment Information.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs Incurred in Oil and Gas Property Acquisitions, Exploration, and Development Activities

	United States	Canada	Egypt	Australia	North Sea	Argentina	Other International	Total
	(In millions)							
2010								
Acquisitions:								
Proved	$ 5,604	$ 2,752	$ 325	$	$	$	$	$ 8,681
Unproved	2,497	542	145	32				3,216
Exploration	261	312	477	236	142	136	20	1,584
Development	1,724	611	290	496	475	131		3,727
Costs incurred(1)	$ 10,086	$ 4,217	$ 1,237	$ 764	$ 617	$ 267	$ 20	$ 17,208
(1) Includes capitalized interest and asset retirement costs as follows:								
Capitalized interest	$ 52	$ 23	$ 10	$ 15	$	$ 11	$	$ 111
Asset retirement costs	1,099	98		93		16		1,306
2009								
Acquisitions:								
Proved	$ 196	$ 13	$	$	$	$ 24	$	$ 233
Unproved			39	38				77
Exploration	233	179	438	182	105	97	11	1,245
Development	892	326	245	474	270	47		2,254
Costs incurred(1)	$ 1,321	$ 518	$ 722	$ 694	$ 375	$ 168	$ 11	$ 3,809
(1) Includes capitalized interest and asset retirement costs as follows:								
Capitalized interest	$ 15	$ 12	$ 8	$ 15	$	$ 11	$	$ 61
Asset retirement costs	182	80		38		(7)		293
2008								
Acquisitions:								
Proved	$ 70	$ 5	$	$ (1)	$	$	$	$ 74
Unproved	75							75
Exploration	382	254	193	293	107	256	28	1,513
Development	2,201	580	668	589	364	98		4,500
Costs incurred(1)	$ 2,728	$ 839	$ 861	$ 881	$ 471	$ 354	$ 28	$ 6,162
(1) Includes capitalized interest and asset retirement costs as follows:								
Capitalized interest	$ 20	$ 12	$ 8	$ 9	$ 1	$ 24	$	$ 74
Asset retirement costs	379	117		(7)	12	13		514

Capitalized Costs

The following table sets forth the capitalized costs and associated accumulated depreciation, depletion and amortization, including impairments, relating to the Company s oil and gas production, exploration and development activities:

	United States	Canada	Egypt	Australia	North Sea	Argentina	Other International	Total
				(In millions)				
2010								
Proved properties	$ 30,273	$ 11,679	$ 5,286	$ 4,435	$ 4,078	$ 2,153	$	$ 57,904
Unproved properties	2,791	1,113	542	254	31	259	58	5,048
	33,064	12,792	5,828	4,689	4,109	2,412	58	62,952
Accumulated DD&A	(14,391)	(6,027)	(2,971)	(1,642)	(2,146)	(1,153)		(28,330)
	$ 18,673	$ 6,765	$ 2,857	$ 3,047	$ 1,963	$ 1,259	$ 58	$ 34,622
2009								
Proved properties	$ 22,777	$ 8,172	$ 4,271	$ 3,661	$ 3,477	$ 1,909	$	$ 44,267
Unproved properties	201	405	320	265	14	236	38	1,479
	22,978	8,577	4,591	3,926	3,491	2,145	38	45,746
Accumulated DD&A	(13,270)	(5,780)	(2,319)	(1,256)	(1,844)	(1,000)		(25,469)
	$ 9,708	$ 2,797	$ 2,272	$ 2,670	$ 1,647	$ 1,145	$ 38	$ 20,277

F-54

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs Not Being Amortized

The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2010, by the year in which such costs were incurred. There are no individually significant properties or significant development projects included in costs not being amortized. The majority of the evaluation activities are expected to be completed within five to ten years.

	Total	2010	2009	2008	2007 and Prior
			(In millions)		
Property acquisition costs	$ 4,118	$ 3,491	$ 108	$ 187	$ 332
Exploration and development	802	481	207	40	74
Capitalized interest	128	52	18	30	28
Total	$ 5,048	$ 4,024	$ 333	$ 257	$ 434

Oil and Gas Reserve Information

Effective December 31, 2009, Apache adopted revised oil and gas disclosure requirements set forth by the SEC in Release No. 33-8995, Modernization of Oil and Gas Reporting and as codified by the FASB in ASC Topic 932, Extractive Industries Oil and Gas. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures.

Table of Contents

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The following reserve data only represent estimates and should not be construed as being exact.

Crude Oil, Condensate and Natural Gas Liquids (Thousands of barrels)							Natural Gas (Millions of cubic feet)			
ted tes	Canada	Egypt	Australia	North Sea	Argentina	Total	United States	Canada	Egypt	Austral
,960	94,090	74,315	19,948	186,706	24,535	794,554	1,923,750	1,605,675	818,509	536,1