WPX ENERGY, INC.
Form S-1/A
October 31, 2011

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As filed with the Securities and Exchange Commission on October 28, 2011

Registration No. 333-173808

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

Amendment No. 5 to
Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

WPX Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**45-1836028**
(State or other jurisdiction of Incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

One Williams Center
Tulsa, Oklahoma 74172-0172
(918) 573-2000
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

James J. Bender, Esq.
General Counsel and Corporate Secretary
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Tulsa, Oklahoma 74172-0172
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(Name, address, including zip code, and telephone number, including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this registration statement.

If any of the securities being registered on this Form are being offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box: o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

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

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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Subject to Completion, dated October 28, 2011

PROSPECTUS

Shares

WPX Energy, Inc.

Common Stock

This is the initial public offering of common stock of WPX Energy, Inc. We are offering shares of our common stock. No public market currently exists for our common stock. WPX Energy, Inc. is currently a wholly-owned subsidiary of The Williams Companies, Inc. (Williams).

Our common stock has been approved for listing on the New York Stock Exchange under the symbol WPX.

We anticipate that the initial public offering price will be between $ and $ per share.

***Investing in our common stock involves risks. See Risk Factors beginning on page 16 of this prospectus*.**

	Per Share	Total
Price to the public	$	$
Underwriting discounts and commissions	$	$
Proceeds to us (before expenses)	$	$

We have granted the underwriters a 30-day option to purchase up to an additional shares of common stock on the same terms and conditions set forth above if the underwriters sell more than shares of common stock in this offering. Any shares of common stock issued pursuant to this option will not increase the total number of shares of common stock outstanding after this offering, but rather the number of shares of common stock owned by Williams will be reduced share for share by the number of shares of common stock issued pursuant to such option, thus reducing Williams ownership interest in us. We will distribute the net proceeds from the sale of shares of common stock pursuant to this option to Williams as part of our restructuring transactions described herein. Williams is deemed to be an underwriter with respect to any shares of common stock issued pursuant to this option.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed on the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Barclays Capital, on behalf of the underwriters, expects to deliver the shares on or about , 2011.

Barclays Capital **Citigroup** **J.P. Morgan** **BofA Merrill Lynch**

Deutsche Bank Securities	**Goldman, Sachs & Co.**	**Morgan Stanley**	**Wells Fargo Securities**

Credit Suisse	**RBC Capital Markets**	**Scotia Capital**
UBS Investment Bank		**Howard Weil Incorporated**

Prospectus dated , 2011

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You should rely only on the information contained in this document or any free writing prospectus prepared by or on behalf of us. We have not authorized anyone to provide you with information that is different. This document may only be used where it is legal to sell these securities. The information in this document may only be accurate on the date of this document.

Dealer Prospectus Delivery Obligation

Until , 2011 (the 25th day after the date of this prospectus), all dealers that effect transactions in our common shares, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer s obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

Industry and Market Data

We obtained the market and competitive position data used throughout this prospectus from our own research, surveys or studies conducted by third parties and industry or general publications. Industry publications and surveys generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While we believe that each of these studies and publications is reliable and have no reason to believe they are inaccurate or incomplete, neither we nor the underwriters have independently verified such data and neither we nor the underwriters make any representation as to the accuracy of such information. Similarly, we believe our internal research is reliable but it has not been verified by any independent sources.

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CERTAIN DEFINITIONS

The following oil and gas measurements and industry and other terms are used in this prospectus. As used herein, production volumes represent sales volumes, unless otherwise indicated.

Bakken Shale means the Bakken Shale oil play in the Williston Basin and can include the Upper Three Forks formation.

Barrel means one barrel of petroleum products that equals 42 U.S. gallons.

BBtu means one billion BTUs.

BBtu/d means one billion BTUs per day.

Bcfe means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Bcf/d means one billion cubic feet per day.

Boe means barrels of oil equivalent.

Boe/d means barrels of oil equivalent per day.

British Thermal Unit or BTU means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

FERC means the Federal Energy Regulatory Commission.

Fractionation means the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane.

LOE means lease and other operating expense excluding production taxes, ad valorem taxes and gathering, processing and transportation fees.

Mbbls means one thousand barrels.

Mboe/d means thousand barrels of oil equivalent per day.

Mcf means one thousand cubic feet.

Mcfe means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMbbls means one million barrels.

MMboe means one million barrels of oil equivalent.

MMBtu means one million BTUs.

MMBtu/d means one million BTUs per day.

MMcf means one million cubic feet.

MMcf/d means one million cubic feet per day.

MMcfe means one million cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMcfe/d means one million cubic feet of gas equivalent per day using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

NGLs means natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

PROSPECTUS SUMMARY

This summary highlights certain information contained elsewhere in this prospectus. This summary is not complete and does not contain all of the information that you should consider before investing in our common stock. You should read this entire prospectus carefully, including the risks discussed under Risk Factors and the financial statements and notes thereto included elsewhere in this prospectus. Some of the statements in this summary constitute forward-looking statements. See Forward-Looking Statements.

Except where the context otherwise requires or where otherwise indicated, (1) all references to Williams refer to The Williams Companies, Inc., our parent company, and its subsidiaries, other than us, and (2) all references to WPX Energy, WPX, the Company, we, us and our refer to WPX Energy, Inc. and its subsidiaries.

Overview

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserve base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our positions in the Bakken Shale oil play in North Dakota and the Marcellus Shale natural gas play in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International, Inc. (Apco), which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol APAGF.

We have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. For the five years ended December 31, 2010, we have grown production at a compound annual growth rate of 12 percent. As of December 31, 2010, our proved reserves were 4,473 Bcfe, 59 percent of which were proved developed reserves. Average daily production for the month of September 2011 was 1,374 MMcfe/d. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

The following table provides summary data for each of our primary areas of operation as of December 31, 2010, unless otherwise noted.

	Estimated Net Proved Reserves		September 2011 Average Daily Net Production			2011 Budget Estimate	
		% Proved				Drilling Capital(2)	PV-10(3)
Basin/Shale	Bcfe	Developed	(MMcfe/d)(1)	Net Acreage	Gross Wells	(Millions)	(Millions)
Piceance Basin	2,927	53%	806	211,000	376	$ 575	$ 2,707
Bakken Shale(4)	136	11%	36	89,420	41	260	399
Marcellus Shale	28	71%	16	99,301	62	170	29
Powder River Basin	348	75%	235	425,550	411	70	317

San Juan Basin	554	79%	145	120,998	51	40	477
Apco(5)	190	60%	54	404,304	37	30	358
Other(6)	290	72%	82	327,390	94	85	257
Total	4,473	59%	1,374	1,677,963	1,072	$ 1,230	$ 4,544

(1) Represents average daily net production of our continuing operations for the month of September 2011.

(2) Based on the midpoint of our estimated capital spending range.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure), the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. For a

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definition of PV-10 and a reconciliation of PV-10 to Standardized Measure, see Summary Combined Historical Operating and Reserve Data Non-GAAP Financial Measures and Reconciliations below.

(4) Our estimated net proved reserves in the Bakken Shale have not been audited by independent reserve engineers.

(5) Represents approximately 69 percent of each metric (which corresponds to our ownership interest in Apco) except Percent Proved Developed, Gross Wells and Drilling Capital.

(6) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties. September 2011 average daily net production excludes Arkoma production of approximately nine MMcfe/d as our Arkoma Basin operations were classified as held for sale and reported as discontinued operations as of June 30, 2011.

In addition to our exploration and development activities, we engage in natural gas sales and marketing. See Business Gas Management.

Bakken Shale and Marcellus Shale Acquisitions

An important part of our strategy to grow our business and enhance shareholder value is to acquire properties complementary to our existing positions as well as undeveloped acreage with significant resource potential in new geographic areas. Our management team applies a disciplined approach to making acquisitions and evaluates potential acquisitions of oil and gas properties based on three key criteria: (i) a location in the core of a large, unconventional resource area, (ii) the availability of contiguous, scalable acreage positions and (iii) the ability to replicate our cost-efficient model. In 2010, we invested approximately $1.7 billion on properties in the Bakken Shale and Marcellus Shale that met these criteria. Approximately 35 percent of our 2011 drilling capital budget will be dedicated to our Bakken Shale and Marcellus Shale properties, and our management currently expects approximately 47 percent of our 2012 drilling expenditures to be dedicated to properties in these regions.

Bakken Shale

We have acquired 89,420 net acres in the Williston Basin in North Dakota that is prospective for oil in the Bakken Shale. We acquired substantially all of this acreage in December 2010 through the acquisition of Dakota-3 E&P Company LLC for $949 million in cash. Our entry into the Bakken Shale oil play is part of our strategy to diversify our commodity exposure through the addition of oil and liquids-rich development opportunities to our portfolio.

We currently have four rigs operating on our Bakken Shale acreage, with a fifth rig expected to be active in the fourth quarter of 2011. We have contracted for a sixth rig, which we expect to be operating by mid 2012 and to have the majority of all related drilling permits in place by the end of 2011. Since acquiring this acreage, we have drilled 16 operated wells on our Bakken Shale properties, 15 Middle Bakken formation wells and one Three Forks formation well. There have been 20 wells completed and connected to sales, with initial 30 day production rates ranging from 600 Boe/d to 1,300 Boe/d.

Marcellus Shale

Our 99,301 net acres as of December 31, 2010 in the Marcellus Shale were acquired through two key transactions and additional leasing activities. In June 2009, we entered into a drill to earn agreement with Rex Energy Corporation in Pennsylvania s Westmoreland, Clearfield and Centre Counties. We have acquired and operate approximately 22,000 net acres pursuant to such agreement. Following this initial venture, in July 2010, we acquired 42,000 net acres primarily located in Susquehanna County in northeastern Pennsylvania for $599 million. In addition, during 2010 we spent a total of $164 million to acquire additional unproved leasehold acreage positions in the Marcellus Shale.

Currently, we have four rigs operating in the Marcellus Shale. We expect to increase our level of drilling activity to six to seven rigs by the end of 2012 and continue to increase drilling activity thereafter, subject to permitting, rig availability and the then prevailing commodity price environment.

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Our Business Strategy

Our business strategy is to increase shareholder value by finding and developing reserves and producing natural gas, oil and NGLs at costs that generate an attractive rate of return on our investment.

Efficiently Allocate Capital for Optimal Portfolio Returns. We expect to allocate capital to the most profitable opportunities in our portfolio based on commodity price cycles and other market conditions, enabling us to continue to grow our reserves and production in a manner that maximizes our return on investment. In determining which drilling opportunities to pursue, we target a minimum after-tax internal rate of return on each operated well we drill of 15 percent. While we have a significant portfolio of drilling opportunities that we believe meet or exceed our return targets even in challenging commodity price environments, we are disciplined in our approach to capital spending and will adjust our drilling capital expenditures based on our level of expected cash flows, access to capital and overall liquidity position. For example, in 2009 we demonstrated our capital discipline by reducing drilling expenditures in response to prevailing commodity prices and their impact on these factors.

Continue Our Cost-Efficient Development Approach. We focus on developing properties where we can apply development practices that result in cost efficiencies. We manage costs by focusing on establishing large scale, contiguous acreage blocks where we can operate a majority of the properties. We believe this strategy allows us to better achieve economies of scale and apply continuous technological improvements in our operations. We intend to replicate these cost-efficient approaches in our recently acquired growth positions in the Bakken Shale and the Marcellus Shale.

Pursue Strategic Acquisitions with Significant Resource Potential. We have a history of acquiring undeveloped properties that meet our disciplined return requirements and other acquisition criteria to expand upon our existing positions as well as acquiring undeveloped acreage in new geographic areas that offer significant resource potential. This is illustrated by our recent acquisitions in the Bakken Shale and the Marcellus Shale. We seek to continue expansion of current acreage positions and opportunistically acquire acreage positions in new areas where we feel we can establish significant scale and replicate our cost-efficient development approach.

Target a More Balanced Commodity Mix in Our Production Profile. With our Bakken Shale acquisition in December 2010 and our liquids-rich Piceance Basin assets, we have a significant drilling inventory of oil- and liquids-rich opportunities that we intend to develop rapidly in order to achieve a more balanced commodity mix in our production. We refer to the Piceance Basin as liquids-rich because our proved reserves in that basin consist of wet, as opposed to dry, gas and have a significant liquids component. Our current estimated proved reserves of NGLs and condensate in the Piceance Basin are 95 MMbbl and 3 MMbbl, respectively. We will continue to pursue other oil- and liquids-rich organic development and acquisition opportunities that meet our investment returns and strategic criteria.

Maintain Substantial Financial Liquidity and Manage Commodity Price Sensitivity. We plan to conservatively manage our balance sheet and maintain substantial liquidity through a mix of cash on hand and availability under our credit facility. In addition, we have engaged and will continue to engage in commodity hedging activities to maintain a degree of cash flow stability. Typically, we target hedging approximately 50 percent of expected revenue from domestic production during a current calendar year in order to strike an appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. At September 30, 2011, our estimated domestic natural gas production revenues were 67 percent hedged for 2011 and 48 percent hedged for 2012. Estimated domestic oil production revenues were 48 percent hedged for 2011 and 49 percent hedged for 2012 as of the same date.

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Our Competitive Strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

A Leading Piceance Basin Cost Structure. We have a large position in the lower cost valley area of the Piceance Basin, which we believe provides us economies associated with lower elevation drilling and large contiguous operations, allowing us to continuously drive down operating costs and increase efficiencies. The existing substantial midstream infrastructure in the Piceance Basin contributes to our cost-efficient structure and provides take-away capacity for our natural gas and NGLs. Because of this cost-efficient structure in the Piceance Basin, we have the ability to generate returns that we believe are in excess of those typically associated with Rockies producers.

Attractive Asset Base Across a Number of High Growth Areas. In addition to our large scale Piceance Basin properties, our assets include emerging, high growth opportunities such as our Bakken Shale and Marcellus Shale positions. Based on our subsurface geological and engineering analysis of available well data, we believe our Bakken Shale and Marcellus Shale positions are located in core areas of these plays, which have associated historic drilling results that we believe offer highly attractive economic returns.

Extensive Drilling Inventory. As of December 31, 2010, we have identified approximately 2,900 proved undeveloped drilling locations. We have budgeted drilling approximately 500 gross operated wells during 2011. We have established significant scale in each of our core areas of operation that support multi-year development plans and allow us to optimally leverage our cost-efficient development approach. Our drilling inventory provides opportunities across diverse geographic markets and products including natural gas, oil and NGLs.

Significant Operating Flexibility. In the Piceance Basin, Bakken Shale and Marcellus Shale, our three primary basins, we operate substantially all of our production. We expect approximately 91 percent of our projected 2011 domestic drilling capital will be spent on projects we operate. We believe acting as operator on our properties allows us to better control costs and capital expenditures, manage efficiencies, optimize development pace, ensure safety and environmental stewardship and, ultimately, maximize our return on investment. As operator, we are also able to leverage our experience and expertise across all basins and transfer technology advances between them as applicable. In addition, substantially all of our Piceance Basin properties are held by producing wells, which allows us to adjust our level of drilling activity in response to changing market conditions.

Significant Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. Immediately following the completion of this offering, we expect to have $2.0 billion of liquidity, comprised of availability under our $1.5 billion credit facility and approximately $500 million of cash on hand. We believe our pro forma level of debt to proved reserves is low relative to a majority of other publicly traded, independent oil and gas producers.

Management Team with Broad Unconventional Resource Experience. Our management and operating team has significant experience acquiring, operating and developing natural gas and oil reserves from tight-sands and shale formations. Our Chief Executive Officer and his direct reports have in excess of 238 collective years of experience running large scale drilling programs and drilling vertical and horizontal wells requiring complex well design and completion methods. Our team has demonstrated the ability to manage large scale operations and apply current technological successes to new development opportunities. We have deployed members of our successful Piceance Basin, Powder River Basin and Barnett Shale teams to the Bakken Shale and Marcellus Shale teams to help replicate our cost-efficient model and to apply our highly specialized technical expertise in the development of those resources.

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Our Relationship with Williams

We are currently a wholly-owned subsidiary of The Williams Companies, Inc., an integrated energy company with 2010 consolidated revenues in excess of $9 billion that trades on the New York Stock Exchange (NYSE) under the symbol WMB. We were formed in April 2011 to hold Williams exploration and production business and to effect this offering and the related transactions.

Upon the completion of this offering, we will be a public company, and Williams will own % of our outstanding shares of common stock (% if the underwriters exercise their option to purchase additional shares in full). As a result, Williams will have the ability to elect all of the members of our board of directors and to determine the outcome of other matters submitted to a vote of our stockholders. For a discussion of related risks, please read Risk Factors Risks Related to Our Relationship with Williams.

We intend to distribute to Williams a substantial portion of the proceeds we receive in this offering and our concurrent sale of debt securities. See Use of Proceeds. Williams has advised us that it intends to use the funds it receives from the proceeds of this offering and our concurrent sale of debt securities to repay a portion of its indebtedness, and that following the completion of this offering, it intends to distribute all of the shares of our common stock that it owns through a tax-free distribution, or spin-off, to Williams stockholders. The determination of whether, and if so, when, to proceed with the spin-off is entirely within the discretion of Williams, although Williams has indicated its intention to complete the spin-off following this offering no later than the first quarter of 2012. Williams has the sole discretion to determine the form, the structure and all other terms of any transactions to effect the spin-off. If Williams does not proceed with the spin-off, it could elect to dispose of our common stock in a number of different types of transactions, including additional public offerings, open market sales, sales to one or more third parties or split-off offerings that would allow Williams stockholders the opportunity to exchange Williams shares for shares of our common stock or a combination of these transactions. Except for the lock-up period described under Underwriting, Williams is not subject to any contractual obligation to maintain its share ownership. For more information on the potential effects of Williams disposition of our common stock by means of the anticipated spin-off or otherwise, please read Risk Factors Risks Related to Our Relationship with Williams.

We currently depend on Williams for a number of administrative functions. Prior to the completion of this offering, we will enter into agreements with Williams related to the separation of our business operations from Williams. These agreements will be in effect as of the completion of this offering and will govern various interim and ongoing relationships between Williams and us, including the extent and manner of our dependence on Williams for administrative services following the completion of this offering. Under the terms of these agreements, we are entitled to the ongoing assistance of Williams only for a limited period of time following the spin-off. For more information regarding these agreements, see Arrangements Between Williams and Our Company and the historical combined financial statements and the notes thereto included elsewhere in this prospectus. All of the agreements relating to our separation from Williams will be made in the context of a parent-subsidiary relationship and will be entered into in the overall context of our separation from Williams. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties. See Risk Factors Risks Related to Our Relationship with Williams We may have potential business conflicts of interest with Williams regarding our past and ongoing relationships, and because of Williams controlling ownership in us, the resolution of these conflicts may not be favorable to us.

Our planned two-step separation process ((1) our initial public offering and concurrent sale of debt securities, including a distribution of a portion of the debt proceeds to Williams, followed by (2) a spin-off of our common stock in the form of a distribution by Williams to its stockholders) provides us with capital and enables Williams to repay debt while simultaneously achieving the benefits of our complete separation from Williams in a tax-efficient manner.

In addition, we believe that our separation from Williams will enable us to realize the following benefits:

Focused management attention. Our separation from Williams will allow us to focus managerial attention solely on our business, resulting in stream-lined decision making, more efficient deployment of resources and increased operational flexibility.

Direct access to the debt and equity capital markets. As a separate public company, we will have direct access to the capital markets, thereby enabling us to optimize our capital structure to meet the specific needs of our business.

Enhancing our market recognition with investors. We believe our simpler corporate structure with a single business segment will allow us to fit more purely into an exploration and production investor sector and attract pure play investors.

Improving our ability to pursue acquisitions. As a stand alone exploration and production company, we will be better positioned to use our equity securities as capital in pursuing merger and acquisition activities. However, we will be subject to certain requirements, such as (1) prior to the spin-off to Williams shareholders of its retained shares in us, Williams must satisfy certain 80% ownership thresholds and (2) after the spin-off, we must avoid a 50% or greater change in our ownership in transactions related to the spin-off. Both of these limitations are necessary in order to maintain the tax-free treatment of our separation from Williams. See Risk Factors Risks Related to our Relationship with Williams Our agreements with Williams may limit our ability to obtain additional financing or make acquisitions, and Risk Factors Risks Related to our Relationship with Williams Our tax sharing agreement with Williams may limit our ability to take certain actions and may require us to indemnify Williams for significant tax liabilities.

Our Restructuring

Prior to the completion of this offering:

Williams will contribute and transfer to us the assets and liabilities associated with our business and will contribute to our capital all intercompany debt associated with our business; and

we will amend and restate our certificate of incorporation and bylaws.

We refer to these transactions as our restructuring transactions.

Concurrent Financing Transactions

On June 3, 2011, we entered into a new five-year $1.5 billion senior unsecured revolving credit facility agreement (the Credit Facility), which will become effective prior to the completion of this offering upon the satisfaction of certain conditions and for which we will pay associated financing costs. Concurrently with or shortly following the consummation of this offering, we expect to issue up to $1.5 billion aggregate principal amount of senior unsecured notes (the Notes) and pay associated financing costs. We expect to retain approximately $500 million of the net proceeds from the concurrent issuance of the Notes. At current commodity prices, we expect as much as 50 percent of those proceeds could be used for capital expenditures for drilling and facilities projects, with the remainder available to provide additional liquidity and for acquisition, exploration and general corporate purposes. This offering of our common stock is not contingent upon the effectiveness of the Credit Facility or the completion of the offering of the Notes. See Description of Our Concurrent Financing Transactions for a more detailed description of these transactions.

Risk Factors

Investing in our common stock involves substantial risk. You should carefully consider all of the information in this prospectus and, in particular, you should evaluate the risk factors and other cautionary statements set forth under Risk

Factors beginning on page 16 in deciding whether to invest in our common stock. In particular:

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms.

Failure to replace reserves may negatively affect our business.

Exploration and development drilling may not result in commercially productive reserves.

Estimating reserves and future net revenues involves uncertainties. Decreases in natural gas and oil prices, or negative revisions to reserve estimates or assumptions as to future natural gas and oil prices may lead to decreased earnings, losses or impairment of natural gas and oil assets.

Prices for natural gas, oil and NGLs are volatile, and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain our existing business.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities.

Our risk management and measurement systems and hedging activities might not be effective and could increase the volatility of our results.

Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, including with respect to hydraulic fracturing, which may expose us to significant costs and liabilities and could exceed current expectations.

Certain of our properties, including our operations in the Bakken Shale, are located on Native American tribal lands and are subject to various federal and tribal approvals and regulations, which may increase our costs and delay or prevent our efforts to conduct planned operations.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

Our historical and pro forma combined financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

As long as we are controlled by Williams, your ability to influence the outcome of matters requiring stockholder approval will be limited.

Principal Executive Offices

WPX was incorporated under the laws of the State of Delaware in April 2011 and, until the completion of this offering, will be a wholly-owned subsidiary of Williams. Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000. Our website address will be www.wpxenergy.com. Information contained on our website is not incorporated by reference into this prospectus, and you should not consider information on our website as part of this prospectus.

The Offering

Issuer	WPX Energy, Inc.
Common stock offered	shares.
Option to purchase additional shares	shares.
Common stock to be held by Williams after this offering	shares (shares if the underwriters exercise their option to purchase additional shares in full). Any shares of common stock issued pursuant to the underwriters option to purchase additional common shares will not increase the total number of shares of common stock outstanding after this offering, but rather the number of shares of common stock owned by Williams will be reduced share for share by the number of shares of common stock issued pursuant to such option. Williams is deemed to be an underwriter with respect to any shares of common stock issued pursuant to such option.
Common stock outstanding immediately after this offering	shares.
Use of proceeds	We estimate that our net proceeds from the sale of shares of common stock in this offering, after deducting estimated underwriting discounts and commissions and estimated offering expenses, will be approximately $ million ($ million if the underwriters exercise their option to purchase additional common shares in full), assuming the shares are offered at $ per share of common stock, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus. All the net proceeds of this offering will be distributed to Williams. See Use of Proceeds.
Dividend policy	We do not anticipate paying any dividends on our common stock in the foreseeable future. See Dividend Policy.
Exchange Listing	We have been approved to list our shares of common stock on the NYSE under the symbol WPX.

Unless we specifically state otherwise, all information in this prospectus regarding our common stock:

gives effect to our restructuring transactions;

assumes no exercise by the underwriters of their option to purchase additional common shares;

gives effect to a one to stock split that we effected on , 2011; and

excludes shares of common stock reserved for issuance, if any, under equity incentive plans.

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Summary Combined Historical and Unaudited Pro Forma Combined Financial Data

Set forth below is our summary combined historical and unaudited pro forma combined financial data for the periods indicated. The historical unaudited combined financial data for the nine months ended September 30, 2011 and 2010 and balance sheet data as of September 30, 2011 have been derived from our unaudited condensed combined financial statements included in this prospectus. The unaudited condensed combined financial statements have been prepared on the same basis as our audited combined financial statements, except as stated in the related notes thereto, and include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our financial condition and result of operations for such periods. The results of operations for the nine months ended September 30, 2011 presented below are not necessarily indicative of results for the entire fiscal year. The historical financial data for the years ended December 31, 2010, 2009 and 2008 and the balance sheet data as of December 31, 2010 and 2009 have been derived from our audited combined financial statements included in this prospectus.

The pro forma financial data was prepared as if the transactions described below had occurred as of January 1, 2010. The pro forma financial data gives effect to the following transactions:

- the completion of our restructuring transactions;
- the receipt of approximately $718 million from the sale of shares of common stock offered by us at an assumed initial public offering price of $ per share, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us;
- the receipt of approximately $1.5 billion from our expected offering of the Notes, after deducting the discounts of the initial purchasers of the Notes and the expenses payable by us in connection with such offering; and
- the distribution of approximately $1.7 billion to Williams from the combined net proceeds from this offering and the expected offering of the Notes in connection with our restructuring transactions.

You should read the following summary financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical and pro forma financial statements and related notes thereto appearing elsewhere in this prospectus.

The unaudited pro forma combined financial data does not purport to represent what our financial position and results of operations actually would have been had the transactions described above occurred on January 1, 2010 or to project our future financial performance.

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	Pro Forma Nine Months Ended September 30, 2011	Pro Forma Year Ended December 31, 2010	Historical Nine Months Ended September 30, 2011	Historical Nine Months Ended September 30, 2010	Historical Year Ended December 31, 2010	Historical Year Ended December 31, 2009	Historical Year Ended December 31, 2008
			(Millions)				
Statement of Operations Data:							
Revenues, including affiliate(1)	$ 2,996	$ 4,034	$ 2,996	$ 3,074	$ 4,034	$ 3,681	$ 6,184
Costs and expenses:							
Lease and facility operating, including affiliate	218	286	218	207	286	263	272
Gathering, processing and transportation, including affiliate	372	326	372	216	326	273	229
Taxes other than income	109	125	109	109	125	93	254
Gas management (including charges for unutilized pipeline capacity)	1,122	1,771	1,122	1,385	1,771	1,495	3,248
Exploration	107	73	107	45	73	54	37
Depreciation, depletion and amortization	703	875	703	655	875	887	738
Impairment of producing properties and costs of acquired unproved reserves		678		678	678	15	
Goodwill impairment		1,003		1,003	1,003		
General and administrative, including affiliate	208	253	208	183	253	251	247
Gain on sale of contractual right to international production payment							(148)
Other net	4	(19)	4	(6)	(19)	33	6
Total costs and expenses	2,843	5,371	2,843	4,475	5,371	3,364	4,883
Operating income (loss)	153	(1,337)	153	(1,401)	(1,337)	317	1,301
Interest expense, including affiliate	(78)	(106)	(97)	(88)	(124)	(100)	(74)
Interest capitalized	8	16	8	12	16	18	20

Investment income and other	19	21	19	15	21	8	22
Income (loss) from continuing operations before income taxes	102	(1,406)	83	(1,462)	(1,424)	243	1,269
Provision (benefit) for income taxes	36	(144)	29	(167)	(150)	94	452
Income (loss) from continuing operations(2)	66	(1,262)	54	(1,295)	(1,274)	149	817
Loss from discontinued operations(3)	(11)	(8)	(11)	(2)	(8)	(7)	(87)
Net income (loss)	$ 55	$ (1,270)	43	(1,297)	(1,282)	142	730
Less: Net income attributable to noncontrolling interests			7	6	8	6	8
Net income (loss) attributable to WPX Energy			$ 36	$ (1,303)	$ (1,290)	$ 136	$ 722
Income (loss) from continuing operations per share(4):							
Basic and diluted	$	$					

(1) Includes gas management revenues of $1,092 million and $1,357 million for the nine months ended September 30, 2011 and 2010, respectively and $1,742 million, $1,456 million and $3,241 million for the years ended December 31, 2010, 2009 and 2008, respectively. These revenues were offset by the gas management

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expenses shown in the table above. See Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations.

(2) Loss from continuing operations for the nine months ended September 30, 2010 and for the year ended December 31, 2010 includes $1.7 billion of impairment charges related to goodwill, producing properties in the Barnett Shale and costs of acquired unproved reserves in the Piceance Basin. Income from continuing operations in 2008 includes a $148 million gain related to the sale of a right to an international production payment. See Notes 6 and 14 of Notes to Combined Financial Statements for further discussion of asset sales, impairments and other accruals in 2010, 2009 and 2008.

(3) Loss from discontinued operations includes our Arkoma operations which were classified as held for sale in the first half of 2011 and activities associated with Williams former power business that was substantially disposed of in 2007. The loss in 2008 includes a $148 million pre-tax impairment of the Arkoma producing properties.

(4) Historical earnings per share are not presented since the Company s common stock was not part of the capital structure of Williams for the periods presented.

	Pro Forma At September 30, 2011	Historical At September 30, 2011	Historical At December 31, 2010	2009
		(Millions)		
Balance Sheet Data:				
Cash and cash equivalents	$ 550	$ 50	$ 37	$ 34
Properties and equipment, net	8,729	8,729	8,449	7,662
Total assets	10,662	10,141	9,846	10,553
Unsecured notes payable to Williams current			2,261	1,216
Senior unsecured notes	1,500			
Total equity	5,981	7,007	4,500	5,405
Total liabilities and equity	10,662	10,141	9,846	10,553

	Pro Forma Nine Months Ended September 30, 2011	Pro Forma Year Ended December 31, 2010	Historical Nine Months Ended September 30, 2011	2010	Historical Year Ended December 31, 2010	2009	2008
				(Millions)			
Other Financial Data:							
Net cash provided by operating activities			$ 888	$ 852	$ 1,056	$ 1,181	$ 2,009
			(1,056)	(1,433)	(2,337)	(1,435)	(2,252)

Net cash used in investing activities							
Net cash provided (used) by financing activities			181	582	1,284	256	225
Adjusted EBITDAX(1)	$ 990	$ 1,329	990	1,007	1,329	1,299	1,970
Capital expenditures			(1,088)	(1,460)	(1,856)	(1,434)	(2,467)

(1) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss), see Summary Combined Historical Operating and Reserve Data Non-GAAP Financial Measures and Reconciliations below.

Summary Combined Historical Operating and Reserve Data

The following table presents summary combined data with respect to our estimated net proved natural gas and oil reserves as of the dates indicated. Approximately 93 percent of our year-end 2010 U.S. proved reserves estimates were audited by Netherland, Sewell & Associates, Inc. (NSAI) and approximately one percent were audited by Miller and Lents, Ltd. (M&L). Approximately 96 percent of Apco s year-end 2010 proved reserves estimates (which constitute approximately 94 percent of our year-end 2010 proved reserves estimates for international properties) were reviewed and certified by Ralph E. Davis Associates, Inc. In the judgment of these independent reserve petroleum engineers, our estimates reviewed in their respective reports are, in the aggregate, reasonable and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Because our acquisition in the Bakken Shale was completed in late December 2010, our year-end estimated reserves for those properties are based on internal estimates only. All of the reserve estimates mentioned above were prepared in a manner consistent with the rules of the Securities and Exchange Commission (the SEC) regarding oil and natural gas reserve reporting that are currently in effect. You should refer to Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and Business when evaluating the material presented below.

	At December 31, 2010	2009
Estimated Proved Reserves(1)		
Natural Gas (Bcf)(2)	4,214	4,316
Oil (MMbbls)	43	23
Total (Bcfe)	4,473	4,452
PV-10 (in millions)	$ 4,544	$ 2,620
Standardized Measure of Discounted Future Net Cash Flows (in millions)(3)	$ 3,080	$ 1,923

(1) Includes approximately 69 percent of Apco s reserves, which corresponds to our ownership interest in Apco. Our estimated proved reserves for domestic properties, PV-10 and Standardized Measure were derived using an average price of $3.36 per Mcf of natural gas and $48.63 per barrel of oil during 2009 and $4.31 per Mcf of natural gas and $68.89 per barrel of oil during 2010. Our prices were calculated using the 12-month average, first-of-the-month price for the applicable indices for each basin as adjusted for locational price differentials. The 12-month average beginning of the month price for Apco properties was $1.93 per MMbtu of natural gas and $43.62 per barrel of oil for 2009 and $1.63 per MMbtu of natural gas and $52.11 per barrel of oil for 2010.

(2) Net wellhead natural gas reserves at December 31, 2010 and 2009 included approximately 99 MMbbls and 69 MMbbls, respectively, of NGLs to be extracted downstream at processing plants. The gas volume shrink associated with this processing is approximately 216 Bcf and 164 Bcf, respectively, or approximately 4.8 percent and 3.7 percent, respectively, of our total proved reserves volumes.

(3) Standardized Measure represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs and income tax expenses, discounted at ten percent per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes. For a reconciliation of the non-GAAP financial measure of PV-10 to Standardized Measure, the most directly comparable GAAP financial measure, see Non-GAAP Financial Measures and Reconciliations below.

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The following table summarizes our net production for the years indicated.

	Year Ended December 31,		
	2010	**2009**	**2008**
Production Data:			
Natural Gas (MMcf)			
U.S.			
Piceance Basin	241,371	252,387	240,285
Other(1)	162,571	171,691	156,497
Argentina(2)	7,304	7,728	6,392
Total	411,246	431,806	403,174
Oil (MBbls)			
U.S.	857	803	731
Argentina(2)	2,035	1,998	1,991
Total	2,892	2,801	2,722
Combined Equivalent Volumes (MMcfe)(2)	428,598	448,612	419,506
Combined Equivalent Volumes (MBoe)	71,433	74,769	69,918
Average Daily Combined Equivalent Volumes (MMcfe/d)			
U.S.			
Piceance Basin	674	703	666
Other(1)	447	472	430
Argentina(2)	53	54	50
Total	1,174	1,229	1,146

(1) Excludes production from our Arkoma Basin operations which were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our total production.

(2) Includes approximately 69 percent of Apco s production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

The following tables summarize our domestic sales price and cost information for the years indicated.

	Year Ended December 31,		
	2010	**2009**	**2008**
Realized average price per unit(1):			
Natural gas, without hedges (per Mcf)(2)	$ 4.33	$ 3.39	$ 6.84
Impact of hedges (per Mcf)(2)	0.82	1.45	0.09
Natural gas, with hedges (per Mcf)(2)	$ 5.15	$ 4.84	$ 6.93

Oil, without hedges (per Bbl)	$ 66.32	$ 47.39	$ 84.63
Impact of hedges (per Bbl)			
Oil, with hedges (per Bbl)	$ 66.32	$ 47.39	$ 84.63
Price per Boe, without hedges(3)	$ 26.44	$ 20.63	$ 41.52
Price per Boe, with hedges(3)	$ 31.32	$ 29.23	$ 42.03
Price per Mcfe, without hedges(3)	$ 4.41	$ 3.44	$ 6.92
Price per Mcfe, with hedges(3)	$ 5.22	$ 4.87	$ 7.00

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our total revenues.

(2) Includes NGLs.

(3) Realized average prices reflect realized market prices, net of fuel and shrink.

	Year Ended December 31,		
	2010	**2009**	**2008**
Expenses per Mcfe(1):			
Operating expenses:			
Lifting costs and workovers	$ 0.46	$ 0.39	$ 0.45
Facilities operating expense	0.14	0.14	0.15
Other operating and maintenance	0.05	0.05	0.04
Total LOE	$ 0.65	$ 0.58	$ 0.64
Gathering, processing and transportation charges	0.80	0.64	0.57
Taxes other than income	0.27	0.19	0.60
Production cost	$ 1.72	$ 1.41	$ 1.81
General and administrative	$ 0.60	$ 0.56	$ 0.60
Depreciation, depletion and amortization	$ 2.10	$ 2.03	$ 1.80

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations as of June 30, 2011.

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, exploration expenses and the other items described below. Adjusted EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our liquidity. Certain items excluded from Adjusted

EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

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The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measure of net income (loss).

	Pro Forma Nine Months Ended September 30, 2011	Pro Forma Year Ended December 31, 2010	Historical Nine Months Ended September 30, 2011	Historical Nine Months Ended September 30, 2010	Historical Year Ended December 31, 2010	Historical Year Ended December 31, 2009	Historical Year Ended December 31, 2008
	(Millions)						
Adjusted EBITDAX Reconciliation to Net Income (Loss):							
Net income (loss)	$ 55	$ (1,270)	$ 43	$ (1,297)	$ (1,282)	$ 142	$ 730
Interest expense	78	106	97	88	124	100	74
Provision (benefit) for income taxes	36	(144)	29	(167)	(150)	94	452
Depreciation, depletion and amortization	703	875	703	655	875	887	738
Exploration expenses	107	73	107	45	73	54	37
EBITDAX	979	(360)	979	(676)	(360)	1,277	2,031
Gain on sale of contractual right to international production payment							(148)
Impairments of goodwill, producing properties and cost of acquired unproved reserves		1,681		1,681	1,681	15	
Loss from discontinued operations	11	8	11	2	8	7	87
Adjusted EBITDAX	$ 990	$ 1,329	$ 990	$ 1,007	$ 1,329	$ 1,299	$ 1,970

PV-10

PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, discounted at 10 percent per annum to reflect the timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10 and includes 69 percent of Apco s metrics, which corresponds to our ownership interest in Apco, and includes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations as of June 30, 2011.

	At December 31, 2010	At December 31, 2009
	(Millions)	
Standardized Measure of Discounted Future Net Cash Flows	$ 3,080	$ 1,923
Present value of future income tax discounted at 10%	1,464	697
PV-10	$ 4,544	$ 2,620

RISK FACTORS

Investing in our common stock involves substantial risk. You should carefully consider the following risk factors and the other information in this prospectus before investing in our common stock. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could suffer materially and adversely. In that case, the trading price of our common stock could decline, and you might lose all or part of your investment.

Risks Related to Our Business

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, capital contributions or borrowings from Williams and sales of assets. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of natural gas and oil and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our natural gas and oil production or reserves, and in some areas a loss of properties.

Failure to replace reserves may negatively affect our business.

The growth of our business depends upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not always be able to find, develop or acquire additional reserves at acceptable costs. If natural gas or oil prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

Our past success rate for drilling projects should not be considered a predictor of future commercial success. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The new wells we drill or participate in may not be commercially productive, and we may not recover all or any portion of our investment in wells we drill or participate in. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed, canceled or rendered unprofitable or less profitable than anticipated as a result of a variety of other factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, supplies, skilled labor, capital or transportation;

Equipment failures or accidents;

Adverse weather conditions, such as blizzards;

Title and lease related problems;

Limitations in the market for natural gas and oil;

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Unexpected drilling conditions or problems;

Pressure or irregularities in geological formations;

Regulations and regulatory approvals;

Changes or anticipated changes in energy prices; or

Compliance with environmental and other governmental requirements.

We expect to invest approximately 35 percent of our drilling capital during 2011 in two relatively new unconventional projects, the Bakken Shale in western North Dakota and the Marcellus Shale in Pennsylvania. Due to limited production history from the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in those projects.

If natural gas and oil prices decrease, we may be required to take write-downs of the carrying values of our natural gas and oil properties.

Accounting rules require that we review periodically the carrying value of our natural gas and oil properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our natural gas and oil properties. A writedown constitutes a non-cash charge to earnings. For example, as a result of significant declines in forward natural gas prices, we recorded impairments of capitalized costs of certain natural gas properties of $678 million in 2010. In addition, following a weighted average decline in the forward prices for the Powder River Basin from December 31, 2010 to September 30, 2011, we conducted an impairment assessment of our proved producing oil and gas properties in that basin as of September 30, 2011. No impairment was required as of September 30, 2011; however, in this assessment, we noted that the producing assets could be at risk of future impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately six percent on average, absent changes in other factors. These properties will be part of our annual impairment assessment in the fourth quarter of 2011 and could be subject to impairment. If the recording of an impairment charge becomes necessary for these properties as of December 31, 2011, it is reasonably possible that the amount of such charge could be at least $200 million. See Management s Discussion and Analysis of Financial Condition and Results of Operations Overview of the nine months ended September 30, 2011 and 2010. We may incur impairment charges for these or other properties in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Estimating reserves and future net revenues involves uncertainties. Decreases in natural gas and oil prices, or negative revisions to reserve estimates or assumptions as to future natural gas and oil prices may lead to decreased earnings, losses or impairment of natural gas and oil assets.

Reserve estimation is a subjective process of evaluating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are proved reserves are those estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this prospectus represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of

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shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 41 percent of our total estimated proved reserves at December 31, 2010 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

The present value of future net revenues from our proved reserves will not necessarily be the same as the value we ultimately realize of our estimated natural gas and oil reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas and oil reserves. For the year ended December 31, 2008, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect on the day of the estimate in accordance with previous SEC requirements. In accordance with new SEC requirements for the years ended December 31, 2009 and 2010, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our natural gas and oil properties will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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

The majority of our acreage in the Marcellus Shale and Bakken Shale is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, 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, natural gas and oil prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory and lease issues.

Prices for natural gas, oil and NGLs are volatile, and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain our existing business.

Our revenues, operating results, future rate of growth and the value of our business depend primarily upon the prices of natural gas, oil and NGLs. Price volatility can impact both the amount we receive for our products and the volume of products we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The markets for natural gas, oil and NGLs are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, oil and NGLs;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- Variations in local market conditions (basis differential);
- The price and availability of other types of fuels;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and quantity of foreign imports of natural gas and oil;
- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas and oil markets;
- The overall economic environment;
- The credit of participants in the markets where products are bought and sold; and
- The adoption of regulations or legislation relating to climate change.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities.

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Bakken Shale and Marcellus Shale or that we will be able to obtain sufficient transportation capacity on economic terms.

A lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

We may have excess capacity under our firm transportation contracts, or the terms of certain of those contracts may be less favorable than those we could obtain currently.

We have entered into contracts for firm transportation that may exceed our transportation needs. Any excess transportation commitments will result in excess transportation costs that could negatively affect our results of operations. In addition, certain of the contracts we have entered into may be on terms less favorable to us than we could obtain if we were negotiating them at current rates, which also could negatively affect our results of operations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator s breach of the applicable agreements could reduce our production and revenues or increase our costs. As of December 31, 2010, we were not the operator of approximately 17 percent of our total domestic net production. Apco generally has outside-operated interests in its properties. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the operator s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts includes wholesale contracts to buy and sell natural gas, oil and NGLs that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our business, we often extend credit to our counterparties. We are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty s obligation is inadequate, we will suffer a loss. Downturns in the economy or disruptions in the global credit markets could cause more of our counterparties to fail to perform than we expect.

Our risk management and measurement systems and hedging activities might not be effective and could increase the volatility of our results.

The systems we use to quantify commodity price risk associated with our businesses might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this prospectus might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified. Furthermore, no single hedging arrangement can adequately address all commodity price risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract s counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for natural gas, oil and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for natural gas, oil or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) was enacted. The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The final impact of the Dodd-Frank Act on our hedging activities is uncertain at this time due to the requirement that the SEC and the Commodities Futures Trading Commission (CFTC) promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. These new rules and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts or reduce the availability of derivatives. Although we believe the derivative contracts that we enter into should not be impacted by position limits and should be exempt from the requirement to clear transactions through a central exchange or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

Depending on the rules and definitions adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers and counterparties creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

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We face competition in acquiring new properties, marketing natural gas and oil and securing equipment and trained personnel in the natural gas and oil industry.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and oil and securing equipment and trained personnel. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.

There are operational risks associated with drilling for, production, gathering, transporting, storage, processing and treating of natural gas and oil and the fractionation and storage of NGLs, including:

- Hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines, pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), oil, NGLs, brine or industrial chemicals;
- Operator error;
- Pollution and environmental risks;
- Fires, explosions and blowouts;
- Risks related to truck and rail loading and unloading; and
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

We are not fully insured against all risks inherent to our business, including environmental accidents. We do not maintain insurance in the type and amount to cover all possible risks of loss.

We currently maintain excess liability insurance with limits of $610 million per occurrence and in the annual aggregate with a $2 million per occurrence deductible. This insurance covers us, our parent, our subsidiaries and certain of our affiliates for legal and contractual liabilities arising out of bodily injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability for full limits, with the first $135 million of insurance also providing gradual pollution liability coverage for natural gas and NGL operations.

Although we maintain property insurance on property we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets or the entire amount of business interruption loss we may experience. In addition, certain perils may be excluded from coverage or sub-limited.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. We may elect to self insure a portion of our risks. We do not insure our underground pipelines for physical damage, except at certain locations. All of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured it could adversely affect our operations and financial condition.

In addition, any insurance company that provides coverage to us may experience negative developments that could impair their ability to pay any of our claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial and reserves disclosures and companies relationships with their independent public accounting firms and reserves consultants. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact of that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations and financial condition.

Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States, principally Argentina and Colombia. The economic, political and legal conditions and regulatory environment in the countries in which we have interests or in which we might pursue acquisition or investment opportunities present risks that are different from or greater than those in the United States. These risks include delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, including with respect to the prices we realize for the commodities we produce and sell. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain nonrecourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments.

Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.

Our operating results might fluctuate on a seasonal and quarterly basis.

Our revenues can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

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Our debt agreements impose restrictions on us that may limit our access to credit and adversely affect our ability to operate our business.

Our Credit Facility contains various covenants that restrict or limit, among other things, our ability to grant liens to support indebtedness, merge or sell substantially all of our assets, make investments, loans, or advances and enter into certain hedging agreements, make certain distributions, incur additional debt and enter into affiliate transactions. In addition, our Credit Facility contains financial covenants and other limitations with which we will need to comply. Similarly, the indenture governing the Notes will restrict our ability to grant liens to secure certain types of indebtedness and merge or sell substantially all of our assets. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired.

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements. For more information regarding our anticipated debt agreements, please read Description of our Concurrent Financing Transactions.

Our ability to repay, extend or refinance our debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance our debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers and reduced access to credit markets. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases (GHGs) may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

In addition, legislative and regulatory responses related to GHGs and climate change create the potential for financial risk. The U.S. Congress has previously considered legislation and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

Numerous states have announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. Also in 2009, the EPA finalized a GHG emission standard for mobile sources. On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. On November 8, 2010, the EPA also issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA by March 2012 under this rule. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. Several of the EPA s GHG rules are being challenged in pending court proceedings, and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities that could exceed current expectations.

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations inherent in drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

Clean Air Act (CAA) and analogous state laws, which impose obligations related to air emissions;

Clean Water Act (CWA), and analogous state laws, which regulate discharge of wastewaters and storm water from some our facilities into state and federal waters, including wetlands;

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;

Resource Conservation and Recovery Act (RCRA), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities;

National Environmental Policy Act (NEPA), which requires federal agencies to study likely environment impacts of a proposed federal action before it is approved, such as drilling on federal lands;

- Safe Drinking Water Act (SDWA), which restricts the disposal, treatment or release of water produced or used during oil and gas development;
- Endangered Species Act (ESA), and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and
- Oil Pollution Act (OPA) of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulation of above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes the addition of Energy Extraction Activities to its enforcement priorities list. To address its concerns regarding the pollution risks raised by new techniques for oil and gas extraction and coal mining, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Our business may be adversely affected by increased costs due to stricter pollution control equipment requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Legislation has been introduced in the United States Congress called the Fracturing Responsibility and Awareness of Chemicals Act (the FRAC Act) to amend the SDWA to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as require disclosure of the chemical constituents of the fluids used in the fracturing process. Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations in order to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. At this time, it is not clear what action, if any, the United States Congress will take on the FRAC Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. On October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The U.S. Government Accountability Office is also examining the environmental impacts of produced water and the White House Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. Several states have also adopted or considered legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic fracturing, including states in which we operate (e.g., Wyoming, Pennsylvania, Texas, Colorado, North Dakota and New Mexico). The U.S. Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

Our ability to produce gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations, particularly with respect to our Marcellus Shale, San Juan Basin, Bakken Shale and Piceance Basin operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

Legal and regulatory proceedings and investigations relating to the energy industry, and the complex government regulations to which our businesses are subject, have adversely affected our business and may continue to do so. The operation of our businesses might also be adversely affected by changes in regulations or in their interpretation or implementation, or the introduction of new laws, regulations or permitting requirements applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation or increased permitting requirements. Current legal proceedings or other matters against us, including environmental matters, suits, regulatory appeals, challenges to our permits by citizen groups and similar matters, might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations might be revised or reinterpreted, new laws, regulations and permitting requirements might be adopted or become applicable to us, our facilities, our customers, our vendors or our service providers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, several ruptures on third party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed, including new regulations covering gathering pipelines that have not previously been subject to regulation. Such reforms, if adopted, could significantly increase our costs.

Certain of our properties, including our operations in the Bakken Shale, are located on Native American tribal lands and are subject to various federal and tribal approvals and regulations, which may increase our costs and delay or prevent our efforts to conduct planned operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management (BLM) and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to gas and oil operations on Native American tribal lands. These regulations and approval requirements relate to such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. In addition, if our relationships with any of the relevant Native American tribes were to deteriorate, we could face significant risks to our ability to continue the projected development of our leases on Native American tribal lands. One or more of these factors may increase our costs of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct, our natural gas or oil development and production operations on such lands.

Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and gas exploration and development.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws, treaties and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws, treaties or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws, treaties and regulations, it could have a material adverse effect on us.

Among the changes contained in President Obama s budget proposal for fiscal year 2012, released by the White House on February 14, 2011, is the elimination of certain U.S. federal income tax provisions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current expensing of intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Members of Congress have introduced legislation with similar provisions in the current session. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development. The elimination of such federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including the imposition of, or increases in production, severance, or similar taxes) could negatively affect our financial condition and results of operations.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;

- we may assume liabilities that were not disclosed to us or that exceed our estimates;

- properties we acquire may be subject to burdens on title that we were not aware of at the time of acquisition or that interfere with our ability to hold the property for production;

- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;

acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and

we may issue additional equity or debt securities related to future acquisitions.

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Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

We rely on Williams for certain services necessary for us to be able to conduct our business. Williams may outsource some or all of these services to third parties, and a failure of all or part of Williams relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on Williams and others as service providers and on Williams outsourcing relationships, and our limited ability to control certain costs, could have a material adverse effect on our business, results of operations and financial condition.

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Certain of our accounting, information technology, application development and help desk services are currently provided by Williams outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which Williams outsourcing providers may provide services to us present similar risks of business operations located outside of the United States, including risks of interruption of business, war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States.

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, we have been unable to obtain insurance on commercially reasonable terms, or insurance has not been available at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute natural gas, oil, or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

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We have identified two material weaknesses in our internal controls over financial reporting. Our failure to achieve and maintain effective internal controls could have a material adverse effect on our business in the future, on the price of our common stock and our access to the capital markets.

Although we are not currently subject to the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley), during the preparation of our financial statements for each of the three years in the period ended December 31, 2010 and for the three months ended March 31, 2011, two material weaknesses (as defined under Public Company Accounting Oversight Board Standard No. 5) in our internal controls were identified: one relating to the timing of the recognition of certain compression deficiency obligations under compression service agreements, and one reflecting the aggregation of two significant deficiencies relating to aspects of depreciation, depletion and amortization of property, plant and equipment. As a result of these material weaknesses, adjustments to the estimated carrying value of property, plant and equipment aggregating approximately $20 million on a pre-tax basis have been reflected in our financial statements as of December 31, 2010 and adjustments to gathering, processing and transportation expense aggregating approximately $14 million on a pre-tax basis have been reflected in our income statements for the years ended December 31, 2008, 2009 and 2010. We have taken steps to remediate the internal controls related to the material weaknesses, although we cannot provide assurance that these steps will prove to be effective. See Note 2 of Notes to Combined Financial Statements.

We cannot be certain that future significant deficiencies or material weaknesses will not develop or be identified. As of December 31, 2012, we will be required to assess the effectiveness of our internal control over financial reporting under Sarbanes-Oxley, and we will be required to have our independent registered public accounting firm audit the operating effectiveness of our internal control over financial reporting. If we or our independent registered public accounting firm were to conclude that our internal control over financial reporting was not effective, investors could lose confidence in our reported financial information, the price of our common stock could decline and access to the capital markets or other sources of financing could be limited.

Risks Related to Our Relationship with Williams

We may not realize the potential benefits from our separation from Williams.

We may not realize the benefits that we anticipate from our separation from Williams. These benefits include the following:

- allowing our management to focus its efforts on our business and strategic priorities;
- enhancing our market recognition with investors;
- providing us with direct access to the debt and equity capital markets;
- improving our ability to pursue acquisitions through the use of shares of our common stock as consideration; and
- enabling us to allocate our capital more efficiently.

We may not achieve the anticipated benefits from our separation for a variety of reasons. For example, the process of separating our business from Williams and operating as an independent public company may distract our management from focusing on our business and strategic priorities. In addition, although we will have direct access to the debt and equity capital markets following the separation, we may not be able to issue debt or equity on terms acceptable to us or at all. The availability of shares of our common stock for use as consideration for acquisitions also will not ensure that we will be able to successfully pursue acquisitions or that the acquisitions will be successful. Moreover, even with equity compensation tied to our business we may not be able to attract and retain employees as desired. We also may not fully realize the anticipated benefits from our separation if any of the matters identified as risks in this Risk Factors section were to occur. If we do not realize the anticipated benefits from our separation for any reason, our business may be materially adversely affected.

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Our historical and pro forma combined financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical and pro forma combined financial information that we have included in this prospectus has been derived from Williams accounting records and may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. Williams did not account for us, and we were not operated, as a separate, stand-alone company for the historical periods presented. The costs and expenses reflected in our historical financial information include an allocation for certain corporate functions historically provided by Williams, including executive oversight, cash management and treasury administration, financing and accounting, tax, internal audit, investor relations, payroll and human resources administration, information technology, legal, regulatory and government affairs, insurance and claims administration, records management, real estate and facilities management, sourcing and procurement, mail, print and other office services, and other services, that may be different from the comparable expenses that we would have incurred had we operated as a stand-alone company. These allocations were based on what we and Williams considered to be reasonable reflections of the historical utilization levels of these services required in support of our business. We have not adjusted our historical or pro forma combined financial information to reflect changes that will occur in our cost structure and operations as a result of our transition to becoming a stand-alone public company, including changes in our employee base, potential increased costs associated with reduced economies of scale and increased costs associated with the SEC reporting and the NYSE requirements. Therefore, our historical and pro forma combined financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future. For additional information, see Selected Historical Combined Financial Data and Management s Discussion and Analysis of Financial Condition and Results of Operations, and our financial statements and related notes included elsewhere in this prospectus.

Following this offering, we will continue to depend on Williams to provide us with certain services for our business; the services that Williams will provide to us following the separation may not be sufficient to meet our needs, and we may have difficulty finding replacement services or be required to pay increased costs to replace these services after our agreements with Williams expire.

Certain administrative services required by us for the operation of our business are currently provided by Williams and its subsidiaries, including services related to cash management and treasury administration, finance and accounting, tax, internal audit, investor relations, payroll and human resources administration, information technology, legal, regulatory and government affairs, insurance and claims administration, records management, real estate and facilities management, sourcing and procurement, mail, print and other office services. Prior to the completion of this offering, we will enter into agreements with Williams related to the separation of our business operations from Williams, including an administrative services agreement and a transition services agreement. The services provided under the administrative services agreement will commence on the date this offering is completed and terminate upon the earlier of (i) the date immediately prior to the date Williams distributes all of our shares of common stock that it owns to its stockholders (which we refer to as the distribution date) or (ii) sixty days notice by Williams if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law. The services provided under the transition services agreement will commence on the distribution date and terminate upon the earlier of (i) one year after the distribution date or (ii) sixty days notice by either party. In addition, Williams may immediately terminate any of the services it provides to us under the transition services agreement if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law. We believe it is necessary for Williams to provide services for us under the administrative services agreement and the transition services agreement to facilitate the efficient operation of our business as we transition to becoming a stand alone public company. We will, as a result, initially depend on Williams for services following this offering. While these services are being provided to us by Williams, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them will be limited. After the expiration or termination of these agreements, we may not be able to replace these services or enter into appropriate third-party agreements on terms and conditions, including cost, comparable to those that we will receive from Williams under our agreements with Williams. Although we intend to replace portions of the services currently provided by Williams, we may encounter difficulties replacing certain services or be unable to negotiate pricing or other terms as favorable as those we currently have in effect. See Arrangements Between Williams and Our Company Administrative Services and Transition Services Agreements.

Your investment in our common stock may be adversely affected if Williams does not spin-off the common stock owned by Williams.

Williams has advised us that, following the completion of this offering, it intends to spin-off all of the shares of our common stock that it owns to its stockholders. Williams has indicated that it intends to complete the spin-off no later than the first quarter of 2012. Williams may decide not to complete this offering or the spin-off if, at any time, Williams board of directors determines, in its sole discretion, that this offering or the spin-off is not in the best interests of Williams or its stockholders. Unless and until such a spin-off occurs, we will face the risks discussed in this prospectus relating to our continuing relationship with Williams, including its control of us and potential conflicts of interest between Williams and us. In addition, if a spin-off does not occur, the liquidity of the market for our common stock may be constrained for as long as Williams, or a successor controlling shareholder, continues to hold a significant position in our common stock. A lack of liquidity in the market for our common stock may adversely affect our share price.

Our share price may decline because of Williams ability to sell shares of our common stock.

Sales of substantial amounts of our common stock after this offering, or the possibility of those sales, could adversely affect the market price of our common stock and impede our ability to raise capital through the issuance of equity securities. See Shares Eligible for Future Sale for a discussion of possible future sales of our common stock.

After the completion of this offering, Williams will own % of our outstanding common stock, or % if the underwriters exercise their option to purchase additional common shares in full. Williams has advised us that it intends to complete the distribution of all of our common stock owned by Williams to its stockholders no later than the first quarter of 2012. Common stock so distributed will be freely tradable by such Williams stockholders who are not deemed to be our affiliates or are otherwise subject to lock-up agreements.

Williams has no contractual obligation to retain its shares of our common stock, except for a limited period described under Underwriting during which it will not sell any of its shares of our common stock without the consent of Barclays Capital Inc. until 180 days after the date of this prospectus, subject to extension in certain circumstances. Subject to applicable U.S. federal and state securities laws, after the expiration of this 180-day waiting period (or before, with consent of the underwriters to this offering), Williams may sell any and all of the shares of our common stock that it beneficially owns or distribute any or all of these shares of our common stock to its stockholders. This 180-day waiting period does not apply to the distribution by Williams of its remaining ownership interest in us to its common stockholders. The registration rights agreement described elsewhere in this prospectus grants Williams the right to require us to register the shares of our common stock it holds in specified circumstances. In addition, after the expiration of this 180-day waiting period, we could issue and sell additional shares of our common stock. Any sale by Williams or us of our common stock in the public market, or the perception that sales could occur (for example, as a result of the distribution), could adversely affect prevailing market prices for the shares of our common stock.

As long as we are controlled by Williams, your ability to influence the outcome of matters requiring stockholder approval will be limited.

After the completion of this offering, Williams will own % of our outstanding common stock, or % if the underwriters exercise their option to purchase additional common shares in full. As long as Williams has voting control of our company, Williams will have the ability to take many stockholder actions,

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including the election or removal of directors, irrespective of the vote of, and without prior notice to, any other stockholder. As a result, Williams will have the ability to influence or control all matters affecting us, including:

the composition of our board of directors and, through our board of directors, decision-making with respect to our business direction and policies, including the appointment and removal of our officers;

any determinations with respect to acquisitions of businesses, mergers, or other business combinations;

our acquisition or disposition of assets;

our capital structure;

changes to the agreements relating to our separation from Williams;

our payment or non-payment of dividends on our common stock; and

determinations with respect to our tax returns.

Williams interests may not be the same as, or may conflict with, the interests of our other stockholders. As a result, actions that Williams takes with respect to us, as our controlling stockholder, may not be favorable to us. In addition, this voting control may discourage transactions involving a change of control of our company, including transactions in which you, as a holder of our common stock, might otherwise receive a premium for your shares over the then-current market price. Furthermore, Williams is not prohibited from selling a controlling interest in our company to a third party without your approval or without providing for a purchase of your shares. At any time following the completion of this offering and the expiration or waiver of the applicable lock-up period described under Underwriting, Williams has the right to spin-off shares of our common stock that it owns to its stockholders. In addition, after the expiration or waiver of the applicable lock-up period described under Underwriting, Williams has the right to sell a controlling interest in us to a third party, without your approval and without providing for a purchase of your shares. There is no assurance that Williams will effect the spin-off, and if Williams elects not to effect the spin-off, it could remain our stockholder for an extended or indefinite period of time. In addition, Williams may decide not to complete the spin-off if, at any time, Williams board of directors determines, in its sole discretion, that the spin-off is not in the best interests of Williams or its stockholders. As a result, the spin-off may not occur by 2012 or at all. See Shares Eligible For Future Sale.

We may have potential business conflicts of interest with Williams regarding our past and ongoing relationships, and because of Williams controlling ownership in us, the resolution of these conflicts may not be favorable to us.

Conflicts of interest may arise between Williams and us in a number of areas relating to our past and ongoing relationships, including:

labor, tax, employee benefit, indemnification and other matters arising under agreements with Williams;

employee recruiting and retention;

sales or distributions by Williams of all or any portion of its ownership interest in us, which could be to one of our competitors; and

business opportunities that may be attractive to both Williams and us.

We may not be able to resolve any potential conflicts, and, even if we do so, the resolution may be less favorable to us than if we were dealing with an unaffiliated party.

Finally, in connection with this offering, we will enter into several agreements with Williams. These agreements will be made in the context of a parent-subsidiary relationship and will be entered into in the overall context of our separation from Williams. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties. While we are controlled by Williams,

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Williams may seek to cause us to amend these agreements on terms that may be less favorable to us than the original terms of the agreement.

During the terms of the administrative services agreement and the transition services agreement, and for one year thereafter, neither we nor Williams will be permitted to solicit each other s employees for employment without the other s consent.

Pursuant to the terms of our amended and restated certificate of incorporation, Williams is not required to offer corporate opportunities to us, and certain of our directors and officers are permitted to offer certain corporate opportunities to Williams before us.

Our amended and restated certificate of incorporation provides that, until both (1) Williams and its subsidiaries no longer beneficially own 50% or more of the voting power of all then outstanding shares of our capital stock generally entitled to vote in the election of our directors and (2) no person who is a director or officer of Williams or of a subsidiary of Williams is also a director or officer of ours:

Williams is free to compete with us in any activity or line of business;

we do not have any interest or expectancy in any business opportunity, transaction, or other matter in which Williams engages or seeks to engage merely because we engage in the same or similar lines of business;

to the fullest extent permitted by law, Williams will have no duty to communicate its knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and Williams is free to pursue or acquire such business opportunity, transaction, or other matter for itself or direct the business opportunity, transaction, or other matter to its affiliates; and

if any director or officer of Williams who is also one of our officers or directors becomes aware of a potential business opportunity, transaction, or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us, and will be permitted to communicate or offer that business opportunity to Williams (or its affiliates) and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity or (2) acted in bad faith or in a manner inconsistent with the best interests of our company or our stockholders.

At the completion of this offering, our board of directors will include persons who are also directors and/or officers of Williams. In addition, after the completion of the spin-off of our stock to Williams stockholders, we expect that our board of directors will continue to include persons who are also directors and/or officers of Williams. As a result, Williams may gain the benefit of corporate opportunities that are presented to these directors.

Our agreements with Williams require us to assume the past, present, and future liabilities related to our business and may be less favorable to us than if they had been negotiated with unaffiliated third parties.

We negotiated all of our agreements with Williams as a wholly-owned subsidiary of Williams and will enter into these agreements prior to the completion of this offering. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us. Pursuant to the separation and distribution agreement, we have assumed all past, present and future liabilities (other than tax liabilities which will be governed by the tax sharing agreement as described herein; see Arrangements Between Williams and Our Company Tax Sharing Agreement) related to our business, and we will agree to indemnify Williams for these liabilities, among other matters. Such liabilities include unknown liabilities that could be significant. The allocation of assets and liabilities between Williams and us may not reflect the allocation that would have been reached between two unaffiliated parties. See Arrangements Between Williams and Our Company for a description of these obligations and the allocation of liabilities between Williams and us.

Our agreements with Williams may limit our ability to obtain additional financing or make acquisitions.

We may engage, or desire to engage, in future financings or acquisitions. However, because our agreements with Williams are designed to preserve the tax-free status of the spin-off and any related restructuring transaction, we will agree to certain restrictions in those agreements that may severely limit our ability to effect future financings or acquisitions. For example, for the spin-off of our stock to Williams stockholders to be tax-free to Williams and its stockholders, among other things, Williams must own at least 80% of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors (and at least 80% of the then outstanding shares of any class of non-voting stock) at the time of the spin-off. In addition, after the spin-off, our stock may not undergo a 50% or greater change of ownership (measured by vote or value) in transactions considered related to the spin-off. Therefore, the tax sharing agreement and the separation and distribution agreement restrict our ability to issue or sell additional common stock or other securities (including securities convertible into our common stock) prior to the spin-off to the extent that such issuances or sales would reduce Williams ownership below certain threshold levels, and for a period after the spin-off to the extent that such issuances would cause us to undergo significant ownership changes.

In addition, we will agree in the separation and distribution agreement that we will not (without Williams prior written consent) take any of the following actions prior to the spin-off:

- acquire any businesses or assets with an aggregate value of more than $50 million for all such acquisitions;
- dispose of any assets with an aggregate value of more than $50 million for all such dispositions; and
- acquire any equity or debt securities of any other person with an aggregate value of more than $50 million for all such acquisitions.

The separation and distribution agreement will also provide that for so long as Williams owns 50% or more of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors, we will not (without the prior written consent of Williams) take any actions that could reasonably result in Williams being in breach or in default under any contract or agreement. Also, for so long as Williams is required to consolidate our results of operations and financial position, we may not incur any additional indebtedness (other than under our Credit Facility and the issuance of the Notes) without the prior written consent of Williams.

Our tax sharing agreement with Williams may limit our ability to take certain actions and may require us to indemnify Williams for significant tax liabilities.

Under the tax sharing agreement, we will agree to take reasonable action or reasonably refrain from taking action to ensure that the spin-off of our stock to Williams stockholders and any related restructuring transaction qualify for tax-free status under section 355 and section 368(a)(1)(D) of the Internal Revenue Code of 1986, as amended (the Code) (unless Williams receives a private letter ruling from the Internal Revenue Service (IRS) or the IRS issues other guidance that can be relied on conclusively to the effect that a contemplated matter or transaction would not jeopardize such tax-free status of the spin-off and related restructuring transaction). We will also make various other covenants in the tax sharing agreement intended to ensure the tax-free status of the spin-off and any related restructuring transaction. These covenants restrict our ability to sell assets outside the ordinary course of business, to issue or sell additional common stock or other securities (including securities convertible into our common stock), or to enter into certain other corporate transactions. For example, prior to the spin-off, we may not enter into any transactions that would reduce Williams ownership to less than 80% of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors or 80% of the then outstanding shares of any class of non-voting stock. Similarly, after the spin-off, we may not enter into any transaction that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock (in either case, taking into account shares issued in this offering) in transactions considered related to the spin-off. See Arrangements Between Williams and Our Company Tax Sharing Agreement for a discussion of these restrictions.

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Further, under the tax sharing agreement, we are required to indemnify Williams against certain tax-related liabilities incurred by Williams (including any of its subsidiaries) relating to the spin-off of our stock to Williams stockholders or relating to any related restructuring transaction undertaken by Williams, to the extent caused by our breach of any representations or covenants made in the tax sharing agreement or the separation and distribution agreement, or made in connection with the private letter ruling or tax opinion. These liabilities include the substantial tax-related liability (calculated without regard to any net operating loss or other tax attribute of Williams) that would result if the spin-off of our stock to Williams stockholders failed to qualify as a tax-free transaction.

We will not have complete control over our tax decisions and could be liable for income taxes owed by Williams.

For so long as Williams continues to own at least 80% of the total voting power and value of our common stock, we and our U.S. subsidiaries will be included in Williams consolidated group for U.S. federal income tax purposes. In addition, we or one or more of our U.S. subsidiaries may be included in the combined, consolidated or unitary tax returns of Williams or one or more of its subsidiaries for U.S. state or local income tax purposes. Under the tax sharing agreement, for each period in which we or any of our subsidiaries are consolidated or combined with Williams for purposes of any tax return, Williams will prepare a pro forma tax return for us as if we filed our own consolidated, combined or unitary return, except that such pro forma tax return will only include current income, deductions, credits and losses from us (with certain exceptions), will not include any carryovers or carrybacks of losses or credits and will be calculated without regard to the federal Alternative Minimum Tax. We will reimburse Williams for any taxes shown on the pro forma tax returns, and Williams will reimburse us for any current losses or credits we recognize based on the pro forma tax returns. In addition, by virtue of Williams controlling ownership and the tax sharing agreement, Williams will effectively control all of our U.S. tax decisions in connection with any consolidated, combined or unitary income tax returns in which we (or any of our subsidiaries) are included. The tax sharing agreement provides that Williams will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to us, to prepare and file all consolidated, combined or unitary income tax returns on our behalf (including the making of any tax elections), and to determine the reimbursement amounts in connection with any pro forma tax returns. This arrangement may result in conflicts of interest between Williams and us. For example, under the tax sharing agreement, Williams will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Williams and detrimental to us. See Arrangements Between Williams and Our Company Tax Sharing Agreement.

Moreover, notwithstanding the tax sharing agreement, U.S. federal law provides that each member of a consolidated group is liable for the group s entire tax obligation. Thus, to the extent Williams or other members of Williams consolidated group fail to make any U.S. federal income tax payments required by law, we could be liable for the shortfall. Similar principles may apply for foreign, state or local income tax purposes where we file combined, consolidated or unitary returns with Williams or its subsidiaries for federal, foreign, state or local income tax purposes.

If, following the completion of the spin-off of our stock to Williams stockholders, there is a determination that the spin-off is taxable for U.S. federal income tax purposes because the facts, assumptions, representations, or undertakings underlying the IRS private letter ruling or tax opinion are incorrect or for any other reason, then Williams and its stockholders could incur significant income tax liabilities, and we could incur significant liabilities.

The spin-off will be conditioned upon, among other things, Williams receipt of a private letter ruling from the IRS and an opinion of its outside tax advisor reasonably acceptable to the Williams board of directors, to the effect that the distribution by Williams of the shares of our common stock held by Williams after the offering, and any related restructuring transaction undertaken by Williams, will qualify for U.S. federal income tax purposes as a tax-free transaction under section 355 and section 368(a)(1)(D) of the Code. Williams has received the private letter ruling from the IRS and the opinion from its outside tax advisor to such effect. The ruling and the opinion rely on certain facts, assumptions, representations and undertakings from Williams and us regarding the past and future conduct of the companies respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Williams and its stockholders may not be able to rely on the private letter ruling and opinion of its tax advisor and could be subject to significant tax liabilities. In addition, notwithstanding the opinion of Williams tax advisor, the IRS could conclude upon audit that the spin-off is taxable if it determines that any of these facts, assumptions, representations, or undertakings are, or have become, not correct or have been violated or if it disagrees with the conclusions in the opinion, or for other reasons, including as a result of certain significant changes in the stock ownership of Williams or us after the spin-off. If the spin-off is determined to be taxable for U.S. federal income tax purposes for any reason, Williams and/or its stockholders could incur significant income tax liabilities, and we could incur significant liabilities. For a description of the sharing of such liabilities between Williams and us, see Arrangements Between Williams and Our Company Tax Sharing Agreement.

Third parties may seek to hold us responsible for liabilities of Williams that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of Williams. Under our agreements with Williams, Williams will agree to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure you that we will be able to recover the full amount of our losses from Williams.

Our prior and continuing relationship with Williams exposes us to risks attributable to businesses of Williams.

Williams is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of Williams that are incurred through a breach of the separation and distribution agreement or any ancillary agreement by Williams or its affiliates other than us, or losses that are attributable to Williams in connection with this offering or are not expressly assumed by us under our agreements with Williams. Immediately following this offering, any claims made against us that are properly attributable to Williams in accordance with these arrangements would require us to exercise our rights under our agreements with Williams to obtain payment from Williams. We are exposed to the risk that, in these circumstances, Williams cannot, or will not, make the required payment.

Our directors and executive officers who own shares of common stock of Williams, who hold options to acquire common stock of Williams or other Williams equity-based awards, or who hold positions with Williams, may have actual or potential conflicts of interest.

Ownership of shares of common stock of Williams, options to acquire shares of common stock of Williams and other equity-based securities of Williams by certain of our directors and officers after this offering, and the presence of directors or officers of Williams on our board of directors could create, or appear to create, potential conflicts of interest when those directors and officers are faced with decisions that could have different implications for Williams than they do for us. Certain of our directors will hold director and/or officer positions with Williams or beneficially own significant amounts of common stock of Williams. See Management.

In addition, because our board of directors does not intend to form a compensation committee or nominating and governance committee in connection with the completion of this offering, the Williams compensation committee will make recommendations to our board of directors regarding compensation for our directors and officers, which could also create, or appear to create, similar potential conflicts of interest. See Management for a description of the extent of the relationship between our directors and officers and directors and officers of Williams.

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We will be a controlled company within the meaning of the NYSE rules and, as a result, will qualify for, and intend to rely on, exemptions from certain corporate governance requirements that provide protection to stockholders of other companies.

After the completion of this offering and prior to the spin-off of our stock to Williams stockholders, Williams will own more than 50% of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors, and we will be a controlled company under the NYSE corporate governance standards. As a controlled company, we intend to rely on certain exemptions from the NYSE standards that will enable us not to comply with certain NYSE corporate governance requirements, including the requirements that:

a majority of our board of directors consists of independent directors;

we have a nominating and governance committee that is composed entirely of independent directors, with a written charter addressing the committee s purpose and responsibilities;

we have a compensation committee that is composed entirely of independent directors, with a written charter addressing the committee s purpose and responsibilities; and

we conduct an annual performance evaluation of the nominating and governance committee and compensation committee.

We intend to rely on some or all of these exemptions, and, as a result, prior to the spin-off, you will not have the same protection afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Risks Related to this Offering

No market currently exists for our common stock. We cannot assure you that an active trading market will develop for our common stock.

Prior to this offering, there has been no public market for shares of our common stock. We cannot predict the extent to which investor interest in our company will lead to the development of a trading market on the NYSE or otherwise, or how liquid that market might become. If an active market does not develop, you may have difficulty selling any shares of our common stock that you purchase in this initial public offering. The initial public offering price for the shares of our common stock has been determined by negotiations between us and the representatives of the underwriters, and may not be indicative of prices that will prevail in the open market following this offering.

If our stock price fluctuates after this offering, you could lose a significant part of your investment.

The market price of our stock may be influenced by many factors, some of which are beyond our control, including those described above in Risks Related to Our Business and the following:

the failure of securities analysts to cover our common stock after this offering or changes in financial estimates by analysts;

the inability to meet the financial estimates of analysts who follow our common stock;

strategic actions by us or our competitors;

announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;

variations in our quarterly operating results and those of our competitors;

general economic and stock market conditions;

risks related to our business and our industry, including those discussed above;

changes in conditions or trends in our industry, markets or customers;

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terrorist acts;

future sales of our common stock or other securities; and

investor perceptions of the investment opportunity associated with our common stock relative to other investment alternatives.

As a result of these factors, investors in our common stock may not be able to resell their shares at or above the initial offering price or may not be able to resell them at all. These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance. In addition, price volatility may be greater if the public float and trading volume of our common stock is low.

Future sales, or the perception of future sales, of our common stock may depress the price of our common stock.

The market price of our common stock could decline significantly as a result of sales of a large number of shares of our common stock in the market after this offering, including shares which might be offered for sale by Williams. The perception that these sales might occur could depress the market price. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate.

Upon completion of this offering, we will have shares of common stock outstanding, of which will have been sold in this offering (shares if the underwriters exercise their option to purchase additional common shares in full) and of which will be owned by Williams (shares if the underwriters exercise their option to purchase additional common shares in full). The shares of common stock offered in this offering will be freely tradable without restriction under the Securities Act of 1933, as amended (the Securities Act), except for any shares of common stock that may be held or acquired by our directors, executive officers and other affiliates, as that term is defined in the Securities Act, which will be restricted securities under the Securities Act. Restricted securities may not be sold in the public market unless the sale is registered under the Securities Act or an exemption from registration is available. We will grant registration rights to Williams with respect to the common stock it owns. Any shares registered pursuant to the registration rights agreement with Williams described in Arrangements Between Williams and Our Company will be freely tradable in the public market.

In connection with this offering, we, our directors and executive officers, Williams and its directors and executive officers have each agreed to enter into a lock-up agreement and thereby be subject to a lock-up period, meaning that they and their permitted transferees will not be permitted to sell any of the shares of our common stock for 180 days after the date of this prospectus, subject to certain extensions without the prior consent of the underwriters. Although we have been advised that there is no present intention to do so, the underwriters may, in their sole discretion and without notice, release all or any portion of the shares of our common stock from the restrictions in any of the lock-up agreements described above. See Underwriting.

Also, in the future, we may issue our securities in connection with investments or acquisitions. The amount of shares of our common stock issued in connection with an investment or acquisition could constitute a material portion of our then outstanding shares of our common stock.

We will not receive any benefit if the underwriters exercise their option to purchase additional common shares.

If the underwriters exercise their option to purchase additional common shares, all of our net proceeds from the issuance of such shares will be distributed to Williams in connection with our restructuring transactions. Accordingly, we will receive no benefit from the issuance of any shares of our common stock subject to the underwriters option to purchase additional common shares.

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Our costs may increase as a result of operating as a public company, and our management will be required to devote substantial time to complying with public company regulations.

We have historically operated our business as a segment of a public company. As a stand-alone public company, we may incur additional legal, accounting, compliance and other expenses that we have not incurred historically. After this offering, we will become obligated to file with the SEC annual and quarterly information and other reports that are specified in Section 13 and other sections of the Securities Exchange Act of 1934, as amended (the Exchange Act). We will also be required to ensure that we have the ability to prepare financial statements that are fully compliant with all SEC reporting requirements on a timely basis. In addition, we will also become subject to other reporting and corporate governance requirements, including certain requirements of the NYSE, and certain provisions of Sarbanes-Oxley and the regulations promulgated thereunder, which will impose significant compliance obligations upon us.

Sarbanes-Oxley, as well as new rules subsequently implemented by the SEC and the NYSE, have imposed increased regulation and disclosure and required enhanced corporate governance practices of public companies. We are committed to maintaining high standards of corporate governance and public disclosure, and our efforts to comply with evolving laws, regulations and standards in this regard are likely to result in increased marketing, selling and administrative expenses and a diversion of management s time and attention from revenue-generating activities to compliance activities. These changes will require a significant commitment of additional resources. We may not be successful in implementing these requirements and implementing them could materially adversely affect our business, results of operations and financial condition. In addition, if we fail to implement the requirements with respect to our internal accounting and audit functions, our ability to report our operating results on a timely and accurate basis could be impaired. If we do not implement such requirements in a timely manner or with adequate compliance, we might be subject to sanctions or investigation by regulatory authorities, such as the SEC or the NYSE. Any such action could harm our reputation and the confidence of investors and clients in our company and could materially adversely affect our business and cause our share price to fall.

Failure to achieve and maintain effective internal controls in accordance with Section 404 of Sarbanes-Oxley could have a material adverse effect on our business and stock price.

As a public company, we will be required to document and test our internal control procedures in order to satisfy the requirements of Section 404 of Sarbanes-Oxley, which will require annual management assessments of the effectiveness of our internal control over financial reporting and a report by our independent registered public accounting firm that addresses the effectiveness of internal control over financial reporting. During the course of our testing, we may identify deficiencies which we may not be able to remediate in time to meet our deadline for compliance with Section 404. Testing and maintaining internal control can divert our management s attention from other matters that are important to the operation of our business. We also expect the new regulations to increase our legal and financial compliance costs, make it more difficult to attract and retain qualified officers and members of our board of directors, particularly to serve on our audit committee, and make some activities more difficult, time consuming and costly. We may not be able to conclude on an ongoing basis that we have effective internal control over financial reporting in accordance with Section 404 or our independent registered public accounting firm may not be able or willing to issue an unqualified report on the effectiveness of our internal control over financial reporting. If we conclude that our internal control over financial reporting is not effective, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or their effect on our operations because there is presently no precedent available by which to measure compliance adequacy. If either we are unable to conclude that we have effective internal control over financial reporting or our independent auditors are unable to provide us with an unqualified report as required by Section 404, then investors could lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law. The future payment of dividends will be at the sole discretion of our board of directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our board of directors deems relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

Provisions of Delaware law and our charter documents may delay or prevent an acquisition of us that stockholders may consider favorable or may prevent efforts by our stockholders to change our directors or our management, which could decrease the value of your shares.

Section 203 of the Delaware General Corporation Law and provisions in our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire us without the consent of our board of directors. See Description of Capital Stock Anti-Takeover Effects of Certificate of Incorporation and Bylaws Provisions. These provisions include the following:

- restrictions on business combinations for a three-year period with a stockholder who becomes the beneficial owner of more than 15% of our common stock;
- restrictions on the ability of our stockholders to remove directors;
- supermajority voting requirements for stockholders to amend our organizational documents; and
- a classified board of directors.

Although we believe these provisions protect our stockholders from coercive or otherwise unfair takeover tactics and thereby provide an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our board of directors, these provisions apply even if the offer may be considered beneficial by some stockholders. Further, these provisions may discourage potential acquisition proposals and may delay, deter or prevent a change of control of our company, including through unsolicited transactions that some or all of our stockholders might consider to be desirable. As a result, efforts by our stockholders to change our direction or our management may be unsuccessful.

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FORWARD-LOOKING STATEMENTS

Certain matters contained in this prospectus include forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. These forward-looking statements relate to anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters.

All statements, other than statements of historical facts, included in this prospectus that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. In some cases, forward-looking statements can be identified by various forms of words such as anticipates, believes, seeks, could, may, should, continues, estimates, expects, forecasts, intends, might, g planned, potential, projects, scheduled, will or other similar expressions. These forward-looking statements are b on management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Seasonality of our business; and
- Natural gas, crude oil and NGLs prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this prospectus. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);

The strength and financial resources of our competitors;

Development of alternative energy sources;

The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations (including climate change legislation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;

Changes in maintenance and construction costs;

Changes in the current geopolitical situation;

Our exposure to the credit risk of our customers;

Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;

Risks associated with future weather conditions;

Acts of terrorism; and

Other factors described in Management s Discussion and Analysis of Financial Condition and Results of Operations and Business.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements set forth above. Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. Forward-looking statements speak only as of the date they are made. We disclaim any obligation to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments, except to the extent required by applicable laws. If we update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this prospectus. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors are described in Risk Factors.

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USE OF PROCEEDS

We estimate that our net proceeds from the sale of shares of common stock in this offering, after deducting estimated underwriting discounts and commissions and estimated offering expenses, will be approximately $ million ($ million if the underwriters exercise their option to purchase additional common shares in full), assuming the shares are offered at $ per share of common stock, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus. We expect to distribute the net proceeds from this offering to Williams. Any shares of common stock issued pursuant to the underwriters option to purchase additional common shares will not increase the total number of shares of common stock outstanding after this offering, but rather the number of shares of common stock owned by Williams will be reduced share for share by the number of shares of common stock issued pursuant to such option, thus reducing Williams ownership interest in us. We will distribute the net proceeds from the sale of shares of common stock pursuant to this option to Williams as part of our restructuring transactions. Williams is deemed to be an underwriter with respect to any shares of common stock issued pursuant to this option. See Underwriting.

Concurrently with or shortly following the completion of this offering, we expect to issue up to $1.5 billion aggregate principal amount of Notes in a private offering exempt from registration under the Securities Act. The Notes will be offered and sold solely to qualified institutional buyers pursuant to Rule 144A and in offshore transactions to persons other than U.S. persons as defined in Regulation S under the Securities Act. As part of our restructuring transactions, all of the net proceeds of the sale of the Notes in excess of $500 million will be distributed to Williams. Our offering of common stock is not contingent upon the completion of our offering of the Notes.

At current commodity prices and drilling costs, as much as 50 percent of the net proceeds we retain from the Notes offering is expected to be utilized for capital projects, principally for drilling activities and, to a lesser extent, the construction of gathering lines, compression facilities and other ancillary infrastructure supporting our drilling program, with the remainder utilized to provide additional liquidity to fund similar activities and for general corporate purposes. Our ability to access the capital markets could be constrained in the future depending on various factors, including our credit rating, and we believe it is prudent to maintain sufficient liquidity to fund our drilling plan under reduced commodity prices. Williams has informed us that it expects to use the net proceeds distributed to it from this offering and the offering of the Notes to repay a portion of its indebtedness.

The following table sets forth the anticipated sources and uses of funds we expect to receive from the sale of shares of common stock in this offering and the issuance of the Notes, assuming the underwriters do not exercise their option to purchase additional common shares.

Sources of Funds			**Uses of Funds**		
Estimated net proceeds from the sale of shares of common stock in this offering(1)	$	718	Distribution of the estimated net proceeds from the sale of shares of common stock in this offering to Williams(1)	$	718
			Retention of approximately $500 million of the estimated net proceeds from the issuance of the Notes		500
Estimated net proceeds from the issuance of the Notes(2)		1,479	Distribution of the estimated net proceeds from the issuance of the Notes in excess of $500 million to Williams(2)		979

Total	$ 2,197	$ 2,197

(1) Assumes that the shares are offered at $ per share of common stock, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus.

(2) After deducting estimated initial purchasers discounts and estimated offering expenses. Assumes the Notes are issued at par.

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DIVIDEND POLICY

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain our future earnings to support the growth and development of our business. The payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend upon, among other things, our financial condition, results of operations, capital requirements and development expenditures, future business prospects and any restrictions imposed by future debt instruments.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of September 30, 2011 on an actual basis and pro forma basis to give effect to:

- the completion of our restructuring transactions;
- the receipt of approximately $718 million from the sale of shares of common stock offered by us at an assumed initial public offering price of $ per share, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us; and
- the receipt of approximately $1.5 billion from our expected offering of the Notes, after deducting the discounts of the initial purchasers of the Notes and the expenses payable by us in connection with such offering;
- the distribution of approximately $1.7 billion to Williams from the combined net proceeds from this offering and the expected offering of the Notes in connection with our restructuring transactions.

You should read this table in conjunction with Use of Proceeds, Selected Historical Combined Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical and unaudited pro forma combined financial statements and related notes included elsewhere in this prospectus.

	At September 30, 2011	
	Historical	Pro Forma
	(Millions)	
Cash and cash equivalents(1)	$ 50	$ 550(2)
Long-term debt:		
Senior unsecured credit facility(3)		
Senior unsecured notes		1,500
Total long-term debt		1,500
Equity:		
Owner s net investment	6,729	
Common stock, $.01 par value per share, 2,000,000,000 shares authorized and shares outstanding		
Additional paid-in capital		5,703
Noncontrolling interests	78	78
Accumulated other comprehensive income	200	200
Total equity	7,007	5,981
Total capitalization	$ 7,007	$ 7,481

(1) Williams has agreed to provide us with up to a maximum amount of $20 million with respect to certain information technology transition costs we will incur as a result of our separation from Williams. The actual amount of cash we receive from Williams upon completion of this offering will be reduced by the total amount of such information technology costs already funded by Williams in advance of this offering. As of September 30, 2011, Williams had incurred approximately $2 million related to these costs, resulting in a remaining potential reimbursement of up to approximately $18 million. The pro forma cash and cash equivalents balance does not reflect any cash that Williams might provide to us related to these costs. See Management s Discussion and Analysis of Financial Condition and Results of Operations Management s Discussion and Analysis of Financial Condition and Liquidity Liquidity.

(2) Reflects the retention of $500 million from the estimated net proceeds from the Notes offering.

(3) Our Credit Facility provides for borrowings of up to $1.5 billion, all of which is expected to be available to us upon the effectiveness of that facility. Our future borrowing capacity may be reduced by letters of credit issued under the Credit Facility. See Description of our Concurrent Financing Transactions Credit Facility.

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DILUTION

Our net tangible book value represents the amount of our total tangible assets less total liabilities. As of September 30, 2011, after giving effect to our restructuring transactions, our pro forma net tangible book value was approximately $ million, or approximately $ per share based on million shares of our common stock outstanding immediately prior to the completion of this offering. After giving effect to the sale of our shares of common stock at the assumed initial public offering price per share of $, which is the midpoint of the estimated offering price range set forth on the cover page of this prospectus, the completion of the expected offering of the Notes and the distribution to Williams of approximately $1.7 billion from the combined proceeds from this offering and the expected offering of the Notes, and after deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us, our pro forma net tangible book value as of September 30, 2011 would have been approximately $ million, or $ per share of our common stock. As a result, at the assumed initial public offering price of $, there will be no immediate dilution to new investors purchasing shares of our common stock in this offering.

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SELECTED HISTORICAL COMBINED FINANCIAL DATA

The following tables set forth our selected historical combined financial data for the periods indicated below. The historical unaudited combined financial data for the nine months ended September 30, 2011 and 2010 and balance sheet data as of September 30, 2011 have been derived from our unaudited condensed combined financial statements included in this prospectus. The unaudited condensed combined financial statements have been prepared on the same basis as our audited combined financial statements, except as stated in the related notes thereto, and include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our financial condition and result of operations for such periods. The results of operations for the nine months ended September 30, 2011 presented below are not necessarily indicative of results for the entire fiscal year. Our selected historical combined financial data as of December 31, 2010 and 2009 and for the fiscal years ended December 31, 2010, 2009 and 2008 have been derived from our audited historical combined financial statements included elsewhere in this prospectus. Our selected historical combined financial data as of December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 have been derived from our unaudited accounting records not included in this prospectus.

The financial statements included in this prospectus may not necessarily reflect our financial position, results of operations and cash flows as if we had operated as a stand-alone public company during all periods presented. Accordingly, our historical results should not be relied upon as an indicator of our future performance.

The following selected historical financial and operating data should be read in conjunction with Use of Proceeds, Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations, Arrangements Between Williams and Our Company and our combined financial statements and related notes included elsewhere in this prospectus.

	Nine Months Ended September 30,		Year Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
				(Millions)			
Statement of operations data:							
Revenues	$ 2,996	$ 3,074	$ 4,034	$ 3,681	$ 6,184	$ 4,479	$ 4,627
Income (loss) from continuing operations(1)	54	(1,295)	(1,274)	149	817	192	104
Income (loss) from discontinued operations(2)	(11)	(2)	(8)	(7)	(87)	146	6
Net income (loss)	43	(1,297)	(1,282)	142	730	338	110
Less: Net income attributable to noncontrolling interests	7	6	8	6	8	11	12
Net income (loss) attributable to WPX Energy	$ 36	$ (1,303)	$ (1,290)	$ 136	$ 722	$ 327	$ 98

	As of September 30, 2011	As of December 31, 2010	2009	2008	2007	2006
Balance sheet data						
Notes payable to Williams current(3)	$	$ 2,261	$ 1,216	$ 925	$ 656	$
Notes receivable from Williams						64
Third party debt	2					34
Total assets	10,141	9,846	10,553	11,624	10,571	11,223
Total equity(3)	7,007	4,500	5,405	5,506	4,356	4,376

(1) Loss from continuing operations for the nine months ended September 30, 2010 and the year ended December 31, 2010 includes $1.7 billion of impairment charges related to goodwill, producing properties in the Barnett Shale and costs of acquired unproved reserves in the Piceance Basin. Income from continuing operations in 2008 includes a $148 million gain related to the sale of a right to an international production payment. See Notes 6 and 14 of Notes to Combined Financial Statements for further discussion of asset sales, impairments and other accruals in 2010, 2009 and 2008.

(2) Income (loss) from discontinued operations includes our Arkoma operations which were classified as held for sale as of March 31, 2011 and Williams former power business that was substantially disposed of in 2007. The activity in 2010 and 2009 primarily relates to the Arkoma operations and the remaining indemnity and other obligations related to the former power business. Activity in 2008 reflects a $148 million pre-tax impairment charge related to the producing properties in the Arkoma Basin. Activity in 2007 and 2006 primarily reflects the operations of the power business and 2007 includes a pre-tax gain of $429 million associated with the reclassification of deferred net hedge gains from accumulated other comprehensive income (loss) to earnings based on the determination that the hedged forecasted transactions were probable of not occurring due to the sale of Williams power business. This gain is partially offset by a pre-tax unrealized mark-to-market loss of $23 million, a $37 million loss from operations and $111 million of pre-tax impairments primarily related to the carrying value of certain derivative contracts.

(3) On June 30, 2011, all of our notes payable to Williams were cancelled by Williams. The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in owner s investment as of September 30, 2011.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are currently a wholly owned subsidiary of The Williams Companies, Inc. and were formed in April 2011 to hold the exploration and production businesses of Williams. We did not have material assets or liabilities as a separate corporate entity until the contribution to us by Williams of the businesses described in this prospectus. Williams previously conducted our businesses through various subsidiaries. This prospectus, including the combined financial statements and the following discussion, describes us and our financial condition and operations as if we had held the subsidiaries that were transferred to us on July 1, 2011 or will be transferred to us prior to completion of this offering for all historical periods presented. The following discussion should be read in conjunction with the selected historical combined financial data and the combined financial statements and the related notes included elsewhere in this prospectus. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this prospectus, particularly in Risk Factors and Forward-Looking Statements.

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserve base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our position in the Bakken Shale oil play in North Dakota and our Marcellus Shale natural gas position in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco, which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol APAGF.

In addition to our exploration and development activities, we engage in natural gas sales and marketing. Our sales and marketing activities to date include the sale of our natural gas and oil production, in addition to third party purchases and sales of natural gas, including sales to Williams Partners L.P. (NYSE: WPZ) (Williams Partners) for use in its midstream business. Following the completion of the spin-off of our stock to Williams stockholders, we do not expect to continue to provide these services to Williams Partners on a long-term basis. Our sales and marketing activities currently include the management of various natural gas related contracts such as transportation, storage and related hedges. We also sell natural gas purchased from working interest owners in operated wells and other area third party producers. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in oil and gas revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Basis of Presentation

The combined financial statements included elsewhere in this prospectus have been derived from the accounting records of Williams, principally representing the Exploration & Production segment. We have used the historical results of operations, and historical basis of assets and liabilities of the subsidiaries we do or will own and operate after the consummation of this offering to prepare the combined financial statements. The following discussion and analysis of results of operations, financial condition and liquidity and critical accounting estimates relates to our current continuing operations and should be read in conjunction with the combined financial statements and notes thereto included in this prospectus.

During the first quarter 2011, we initiated a formal process to pursue the divestiture of our holdings in the Arkoma Basin and have recorded pretax impairment charges totalling $16 million based on an estimated fair value less cost to sell. Our daily Arkoma Basin production is approximately 9 MMcfd, or less than one percent of our total production. As we obtained the requisite approval for disposal and met the other criteria necessary for considering these assets as held for sale and the related operations as discontinued, in the first quarter 2011, we have reported our Arkoma operations, including any impairment charges, as discontinued operations for all periods presented. Unless otherwise noted, the following discussion relates to our continuing operations.

The Combined Statements of Operations included elsewhere in this prospectus includes allocations of costs for corporate functions historically provided to us by Williams. These allocations include the following costs:

Corporate Services. Represents costs for certain employees of Williams who provide general and administrative services on our behalf. These charges are either directly identifiable or allocated based upon usage factors for our operations. In addition, we receive other allocated costs for our share of general corporate expenses of Williams, which are determined based on our relative use of the service or on a three-factor formula, which considers revenue, properties and equipment and payroll. All of these costs are reflected in general and administrative expense in the Combined Statement of Operations.

Employee Benefits and Incentives. Represents benefit costs and other incentives, including group health and welfare benefits, pension plans, postretirement benefit plans and employee stock-based compensation plans. Costs associated with incentive and stock-based compensation plans are determined on a specific identification basis for certain direct employees. All other employee benefit costs have historically been allocated using a percentage factor derived from a ratio of benefit costs to salary costs for Williams domestic employees. These costs are included in lease and facility operating expenses and general and administrative expenses in the Combined Statement of Operations.

Subsequent to the completion of this offering, we will be charged for costs related to these corporate services and employee benefits and incentives under an administrative services agreement using methodologies that are consistent with these historic accounting practices.

Interest Expense. Williams utilizes a centralized approach to cash management and the financing of its businesses. Prior to July 2011, cash receipts and cash expenditures for costs and expenses from our domestic operations were transferred to or from Williams on a regular basis and recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams. The notes accrued interest based on Williams weighted average cost of debt and such interest was added monthly to the note principal. In June 2011, Williams contributed to our capital all amounts due to it under these notes and prospectively we expect all of the cash receipts and cash expenditures transferred to or from Williams until the completion of this offering will be considered owner s equity transactions between us and Williams. Subsequent to the completion of this offering, we will maintain separate cash accounts from Williams and our interest expense will relate only to our borrowings (which will consist of the Notes and any amounts drawn under our Credit Facility).

Our management believes the assumptions and methodologies underlying the allocation of expenses from Williams are reasonable. However, such expenses may not be indicative of the actual level of expense that would have been or will be incurred by us if we were to operate as an independent, publicly traded company. We will enter into an administrative services agreement and a transition services agreement with Williams that will provide for continuation for some of these services in exchange for fees specified in these agreements. See Arrangements Between Williams and Our Company.

We believe the assumptions underlying the combined financial statements are reasonable. However, the combined financial statements may not necessarily reflect our future results of operations, financial position and cash flows or what these items would have been had we been a stand-alone company during the periods presented.

Overview of the nine months ended September 30, 2011 and 2010

Domestic production revenues for the first nine months of 2011 were higher than the first nine months of 2010, primarily because of higher production volumes. Offsetting the impact of higher production volumes was an increase in gathering, processing and transportation expenses due to fees as a result of a new long-term agreement following our fourth quarter 2010 sale to Williams Partners of certain gathering and processing assets in the Piceance Basin and increases in other expense categories discussed below. Our September 2010 operating income (loss) was unfavorably affected by a $1 billion full impairment charge related to goodwill and $678 million of pre-tax charges associated with impairments of certain producing properties and costs of acquired unproved reserves.

During late 2010 and 2011, we incurred approximately $11 million of exploratory drilling costs in connection with a Marcellus Shale well in Columbia County, Pennsylvania. Results have been inconclusive and raise substantial doubt about the economic and operational viability of the well. As a result, the costs associated with this well were expensed as exploratory dry hole costs in the nine months ended September 30, 2011. Further, we assessed the impact of this well on our ability to recover the remaining lease acquisition costs associated with the acreage in Columbia County. During the nine months ended September 30, 2011, we recorded a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage that we do not plan to develop. The acreage in Columbia County represents approximately 21 percent of our total undeveloped acreage in the Marcellus Shale.

In our assessment for impairment of producing oil and gas properties at December 31, 2010, we noted that approximately 12 percent of our producing assets, primarily located in the Powder River Basin, could be at risk for impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately 8 to 12 percent, on average, absent changes in other factors impacting estimated future net cash flows. As of September 30, 2011, the impact of changes in forward prices since December 31, 2010 to our cash flow estimates was indicative of a potential impairment. As a result, we conducted an impairment review of our proved producing oil and gas properties in the Powder River Basin as of September 30, 2011. The net book value of our proved producing assets in the Powder River Basin was approximately $500 million as of September 30, 2011. The recording of an impairment charge was not required as of September 30, 2011, as the undiscounted cash flows were greater than the net book value. Our interim impairment assessment included not only a review of forward pricing assumptions but also consideration of other factors impacting estimated future net cash flows, including but not limited to reserve and production estimates, future operating costs, future development costs and production taxes. Our 2011 interim updated reserve estimates for Powder River included 2011 additions to proved reserves. In this interim assessment, we noted that the Powder River producing assets could be at risk of impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately six percent on average, absent changes in other factors. These properties will be part of our annual impairment assessment in the fourth quarter and could be subject to impairment. If the recording of an impairment charge becomes necessary for these properties as of December 31, 2011, it is reasonably possible that the amount of such charge could be at least $200 million.

Highlights of the comparative periods, primarily related to our production activities, include:

	For the Nine Months Ended September 30,		
	2011	2010	% Change
Average daily domestic production (MMcfe/d)	1,211	1,105	+10%
Average daily total production (MMcfe/d)	1,267	1,160	+9%
Domestic production realized average price ($/Mcfe)(1)	$ 5.44	$ 5.29	+3%
Capital expenditures and acquisitions ($ millions)	$ 1,088	$ 1,460	(25)%
Domestic oil and gas revenues ($ millions)	$ 1,799	$ 1,596	+13%
Revenues ($ millions)	$ 2,996	$ 3,074	(3)%
Operating income (loss) ($ millions)	$ 153	$ (1,401)	NM

(1) Realized average prices include market prices, net of fuel and shrink and hedge gains and losses. The realized hedge gain per Mcfe was $0.65 and $0.73 for the first nine months of 2011 and 2010, respectively.

Overview of 2010

The effects of the severe economic recession during late 2008 and 2009 eased during 2010. Crude oil and NGL prices have returned to attractive levels, but natural gas prices have remained low. Forward natural gas

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prices declined during 2010, primarily as a result of significant increases in near- and long-term supplies, which have outpaced near-term demand growth. The decline in forward natural gas prices contributed significantly to impairments we recorded in 2010.

In December 2010, we acquired a company that held approximately 85,800 net acres in North Dakota s Bakken Shale oil play for cash consideration of approximately $949 million. This acquisition diversified our interests into light, sweet crude oil production.

In July 2010, we acquired additional leasehold acreage positions in the Marcellus Shale and a five percent overriding royalty interest associated with these acreage positions for cash consideration of $599 million. These acquisitions nearly doubled our net acreage holdings in the Marcellus Shale. During 2010, we also invested a total of $164 million to acquire additional unproved leasehold acreage positions in the Marcellus Shale.

In November 2010, we completed the sale of certain gathering and processing assets in the Piceance Basin to Williams Partners for consideration of $702 million in cash and approximately 1.8 million Williams Partners common units. Because the Williams Partners common units received by us in this transaction were intended to be (and have since been) distributed through a dividend to Williams, these units have been presented net within equity. In conjunction with this sale, we entered into a gathering and processing agreement with Williams Partners. Prior periods reflect our costs associated with operating these assets as lease and facility operating costs; depreciation, depletion and amortization; and general and administrative. Our gathering, processing and transportation costs after the sale increased as a result of our new agreement with Williams Partners.

Our 2010 operating income (loss) changed unfavorably by $1.7 billion compared to 2009. Operating income (loss) for 2010 includes a $1 billion full impairment charge related to goodwill and $678 million of pre-tax charges associated with impairments of certain producing properties and costs of acquired unproved reserves, while 2009 included an expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts. Partially offsetting these costs is the impact of an improved energy commodity price environment in 2010 compared to 2009. Highlights of the comparative periods, primarily related to our production activities, include:

	Years Ended December 31,		
	2010	2009	% Change
Average daily domestic production (MMcfe/d)	1,121	1,175	(5)%
Average daily total production (MMcfe/d)	1,174	1,229	(4)%
Domestic production realized average price ($/Mcfe)(1)	$ 5.22	$ 4.87	+7%
Capital expenditures and acquisitions ($ millions)	$ 2,805	$ 1,434	+96%
Domestic oil and gas revenues ($ millions)	$ 2,136	$ 2,090	+2%
Revenues ($ millions)	$ 4,034	$ 3,681	+10%
Operating income (loss) ($ millions)	$ (1,337)	$ 317	NM

(1) Realized average prices include market prices, net of fuel and shrink and hedge gains and losses. The realized hedge gain per Mcfe was $0.81 and $1.43 for 2010 and 2009, respectively.

NM: A percentage calculation is not meaningful due to a change in signs.

As a result of significant declines in forward natural gas prices during third quarter 2010, we performed an interim assessment of our capitalized costs related to property and goodwill. As a result of these assessments, we recorded a $503 million impairment charge related to the capitalized costs of our Barnett Shale properties and a $175 million impairment charge related to capitalized costs of acquired unproved reserves in the Piceance Highlands, which were acquired in 2008. Additionally, we fully impaired our goodwill in the amount of $1 billion. These impairments were based on our assessment of estimated future discounted cash flows and other information. See Notes 6 and 14 of Notes to Combined Financial Statements for a further discussion of the impairments.

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Outlook

We believe we are well positioned to execute our business strategy of finding and developing reserves and producing natural gas and oil at costs that will generate an attractive rate of return on our incremental development investments. However, a significant decline in natural gas prices would negatively impact future operating results and increase the risk of nonperformance of counterparties or impairments of long-lived assets.

We believe that our portfolio of reserves provides an opportunity to continue to grow in our strategic areas, including the Piceance Basin, the Marcellus Shale and the Bakken Shale. We are also focused on developing a more balanced portfolio that may include a larger portion of oil and NGLs reserves and production than we have historically maintained, which we believe will generate long-term, sustainable value for shareholders. Currently, we expect 2011 capital expenditures of approximately $1.35 to $1.55 billion. At this time, we expect 2012 capital expenditures to be approximately $1.2 billion to $1.8 billion.

We continue to operate with a focus on increasing shareholder value and investing in our businesses in a way that enhances our competitive position by:

- Continuing to invest in and grow our production and reserves;
- Retaining the flexibility to make adjustments to our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position and liquids-rich basins with high concentrations of NGLs;
- Maintaining our industry leadership position in relationship to costs; and
- Continuing to maintain an active hedging program around our commodity price risks.

Potential risks or obstacles that could impact the execution of our plan include:

- Lower than anticipated energy commodity prices;
- Lower than expected levels of cash flow from operations;
- Unavailability of capital;
- Higher capital costs of developing unconventional shale properties;
- Counterparty credit and performance risk;
- Decreased drilling success;
- General economic, financial markets or industry downturn;
- Changes in the political and regulatory environments; and

Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, supplies, skilled labor or transportation.

We continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

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Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. For the remainder of 2011, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Remainder of 2011 Natural Gas	
		Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Collar agreements	Rockies	45	$5.30 - $7.10
Collar agreements	San Juan	90	$5.27 - $7.06
Collar agreements	Mid-Continent	80	$5.10 - $7.00
Collar agreements	Southern California	30	$5.83 - $7.56
Collar agreements	Northeast	30	$6.50 - $8.14
Fixed price at basin swaps		395	$5.25

	Remainder of 2011 Crude Oil		
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	
WTI Crude Oil fixed-price	4,500	$	96.56

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The following is a summary of our derivative contracts for daily domestic production shown at weighted average volumes and basin-level weighted average prices for the nine months ended September 30, 2011 and 2010:

		Natural Gas Nine Months Ended September 30,			
		2011		2010	
		Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Collar agreements	Rockies	45	$5.30 - $7.10	100	$6.53 -$8.94
Collar agreements	San Juan	90	$5.27 - $7.06	233	$5.74 - $7.82
Collar agreements	Mid-Continent	80	$5.10 - $7.00	105	$5.37 - $7.41
Collar agreements	Southern California	30	$5.83 - $7.56	45	$4.80 - $6.43
Collar agreements	Northeast and other	30	$6.50 - $8.14	27	$5.63 - $6.87
NYMEX and basis fixed-price swaps		365	$5.21	120	$4.39

	Crude Oil Nine Months Ended September 30,			
	2011		2010	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
WTI Crude Oil fixed-price	2,916	95.53		

The following is a summary of our agreements and contracts for daily domestic production shown at weighted average volumes and basin-level weighted average prices for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Collar agreements Rockies	100	$6.53 - $8.94	150	$6.11 - $9.04	170	$6.16 - $9.14
Collar agreements San Juan	233	$5.75 - $7.82	245	$6.58 - $9.62	202	$6.35 - $8.96
Collar agreements Mid-Continent	105	$5.37 - $7.41	95	$7.08 - $9.73	63	$7.02 - $9.72
	45	$4.80 -$6.43				

Collar agreements						
Southern California						
Collar agreements						
Other	28	$5.63 - $6.87				
NYMEX and basis						
fixed-price swaps	120	$4.40	106	$3.67	70	$3.97

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to deliver on a firm basis 200,000 MMbtu/d of natural gas at monthly index pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation, which expires in 2014.

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Results of Operations

Nine Month-Over-Nine Month Results of Operations

The following table and discussion summarize our combined results of operations for the nine months ended September 30, 2011 and 2010.

	Historical Nine Months Ended September 30, 2011	(Millions) % change from 2010	2010
Revenues:			
Oil and gas sales, including affiliate	$ 1,877	13%	$ 1,660
Gas management, including affiliate	1,092	(20)%	1,357
Hedge ineffectiveness and mark-to-market gains	20	(20)%	25
Other	7	(78)%	32
Total revenues	$ 2,996		$ 3,074
Costs and expenses:			
Lease and facility operating, including affiliate	218	5%	207
Gathering, processing and transportation, including affiliate	372	72%	216
Taxes other than income	109		109
Gas management (including charges for unutilized pipeline capacity)	1,122	(19)%	1,385
Exploration	107	138%	45
Depreciation, depletion and amortization	703	7%	655
Impairment of producing properties and costs of acquired unproved reserves		NM	678
Goodwill impairment		NM	1,003
General and administrative, including affiliate	208	14%	183
Other net	4	NM	(6)
Total costs and expenses	$ 2,843		$ 4,475
Operating income (loss)	$ 153		$ (1,401)
Interest expense, including affiliate	(97)	10%	(88)
Interest capitalized	8	(33)	12
Investment income and other	19	27%	15
Income (loss) from continuing operations before income taxes	$ 83		$ (1,462)
Provision (benefit) for income taxes	29	NM	(167)
Income (loss) from continuing operations	$ 54		$ (1,295)

Loss from discontinued operations	(11)	NM	(2)
Net income (loss)	$ 43		$ (1,297)
Less: Net income attributable to noncontrolling interests	7	17%	6
Net income (loss) attributable to WPX Energy	$ 36		$ (1,303)

NM: A percentage calculation is not meaningful due to a change in signs, a zero-value denominator or a percentage change greater than 200.

The $78 million decrease in total revenues is primarily due to the following:

$265 million decrease in gas management revenues primarily due to a 6 percent decrease in average prices on physical natural gas sales and 15 percent lower natural gas sales volumes. We experienced a similar decrease of $263 million in related costs and expenses; and

$25 million decrease in other revenues primarily related to gathering revenues associated with the gathering and processing assets in Colorado s Piceance Basin that we sold to Williams Partners in the fourth quarter of 2010.

Partially offsetting these decreases was an increase in oil and gas sales revenues attributable to increased domestic production volumes. Domestic production volumes increased approximately ten percent, resulting in $153 million revenue increase, while domestic realized average prices (on an Mcfe basis) increased approximately three percent, resulting in a $50 million revenue increase. Oil and gas sales in 2011 and 2010 include approximately $323 million and $196 million, respectively, related to natural gas liquids and approximately $160 million and $39 million, respectively, related to oil and condensate. The increase in NGL revenues is primarily due to higher volumes and prices in our Piceance Basin primarily processed by Williams Partners Willow Creek facility. The increase in crude oil and condensate is primarily related to our Bakken properties which were acquired in the fourth quarter of 2010. The increase in crude oil and condensate offset the decrease in realized natural gas prices.

The $1,632 million decrease in costs and expenses is primarily due to the following:

The absence of $1,681 million of goodwill and property impairments as previously discussed;

$263 million decrease in gas management expenses, primarily due to a 5 percent decrease in average prices on physical natural gas cost of sales and a 15 percent decrease in natural gas sales volumes. This activity represents natural gas purchased in connection with our gas purchase activities for Williams Partners and certain working interest owners share of production and to manage our transportation and storage activities. The sales associated with our marketing of this gas are included in gas management revenues. Also included in gas management expenses are $28 million in the first nine months of 2011 and $35 million in the first nine months of 2010 for unutilized pipeline capacity.

Partially offsetting the decreased costs are increases in costs and expenses, primarily due to the following:

$11 million higher lease and facility operating expenses which reflects higher expenses associated with increased workover, water management and maintenance activity, offset by the absence in 2011 of $28 million in expenses associated with the previously owned gathering and processing assets.

$156 million higher gathering, processing, and transportation expenses primarily as a result of fees paid to Williams Partners in 2011 for gathering and processing associated with certain gathering and processing assets in the Piceance Basin that we sold to Williams Partners in the fourth quarter of 2010 and an increase in natural gas liquids volumes processed at Williams Partners Willow Creek plant. Our domestic gathering, processing and transportation expenses averaged $1.13 per Mcfe in the first nine months of 2011 and $0.72 per Mcfe in the first nine months of 2010. In the first nine months of 2011, gathering, processing and transportation expenses were $104 million ($0.32/Mcfe) higher due to fees paid to Williams Partners pursuant to the gathering and processing agreement associated with the assets we sold to Williams Partners in the fourth quarter of 2010. During the first nine months of 2010, our operating costs were $58 million ($0.19/Mcfe) associated with these assets (primarily reflected in lease and facility operating costs ($28 million) and depreciation, depletion and amortization ($17 million)). These costs are no longer directly incurred as operating costs (but rather as gathering, processing and transportation expenses) as we no longer own or operate these assets. Transportation costs are also higher as a result of the increase in production volumes;

Exploration expense increased primarily due to the previously discussed dry hole and leasehold write-offs of $61 million in Columbia County, Pennsylvania coupled with increased leasehold amortization costs associated with prior period leasehold acquisitions. Partially off-setting these increases is the absence of $15 million in dry hole charges associated with our Paradox basin recognized in 2010.

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$48 million higher depreciation, depletion and amortization expenses reflects higher production volumes partially offset by the absence of $17 million of depreciation expense related to the assets sold to Williams Partner s in 2010;

$25 million higher general and administrative expenses primarily due to higher wages, salary and benefits costs as a result of an increase in the number of employees.

The $1,554 million increase in operating income primarily reflects the absence of goodwill and property impairments offset by increases in gathering, processing and transportation expense, exploration and depreciation, depletion and amortization in 2011 compared to 2010.

Interest expense increased primarily due to higher average amount outstanding under our unsecured notes payable to Williams. Due to cancellation on June 30, 2011 of our intercompany notes with Williams, no affiliate interest expense was recorded after June 30, 2011.

Provision (benefit) for income taxes changed unfavorably due to the pretax income in 2011 compared to the pretax loss in 2010. See Note 7 of the Notes to Condensed Combined Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Year-Over-Year Results of Operations

The following table and discussion summarize our combined results of operations for the years ended December 31, 2010, 2009 and 2008.

	Historical Year Ended December 31, (Millions)				
	2010	*% Change from 2009*	**2009**	*% Change from 2008*	**2008**
Revenues:					
Oil and gas sales, including affiliate	$ 2,225	3%	$ 2,168	(25%)	$ 2,882
Gas management, including affiliate	1,742	20%	1,456	(55%)	3,241
Hedge ineffectiveness and mark-to-market gains and losses	27	50%	18	(38%)	29
Other	40	3%	39	22%	32
Total revenues	$ 4,034		$ 3,681		$ 6,184
Costs and expenses:					
Lease and facility operating, including affiliate	$ 286	9%	$ 263	(3%)	$ 272
Gathering, processing and transportation, including affiliate	326	19%	273	19%	229
Taxes other than income	125	34%	93	(63%)	254
Gas management (including charges for unutilized pipeline capacity)	1,771	18%	1,495	(54%)	3,248

Exploration	73	35%	54	46%	37
Depreciation, depletion and amortization	875	(1%)	887	20%	738
Impairment of producing properties and costs of acquired unproved reserves	678	NM	15	NM	
Goodwill impairment	1,003	NM		NM	
General and administrative, including affiliate	253	1%	251	2%	247
Gain on sale of contractual right to international production payment		NM		NM	(148)
Other net	(19)	NM	33	NM	6
Total costs and expenses	$ 5,371		$ 3,364		$ 4,883
Operating income (loss)	$ (1,337)		$ 317		$ 1,301
Interest expense, including affiliate	(124)	24%	(100)	35%	(74)
Interest capitalized	16	(11%)	18	(10%)	20
Investment income and other	21	163%	8	(64%)	22
Income (loss) from continuing operations before income taxes	$ (1,424)		$ 243		$ 1,269
Provision (benefit) for income taxes	(150)	NM	94	(79%)	452
Income (loss) from continuing operations	$ (1,274)		$ 149		$ 817
Loss from discontinued operations	(8)		(7)		(87)
Net income (loss)	$ (1,282)		$ 142		$ 730
Less: Net income attributable to noncontrolling interests	8	33%	6	(25%)	8
Net income (loss) attributable to WPX Energy	$ (1,290)		$ 136		$ 722

NM: A percentage calculation is not meaningful due to a change in signs, a zero-value denominator or a percentage change greater than 200.

2010 vs. 2009

The increase in total revenues is primarily due to the following:

$57 million higher oil and gas sales revenues from an increase of $142 million resulting from a seven percent increase in domestic realized average prices including the effect of hedges, partially offset by a decrease of $97 million associated with a five percent decrease in domestic production volumes sold. Oil and gas revenues in 2010 and 2009 include approximately $282 million and $136 million, respectively, related to NGLs and approximately $57 million and $38 million, respectively, related to condensate; and

$286 million higher gas management revenues primarily from a 21 percent increase in average prices on domestic physical natural gas sales associated with our transportation and storage contracts. There is a similar increase of $276 million in related costs and expenses.

The increase in costs and expenses is primarily due to the following:

$23 million higher lease and facility operating expenses due to increased activity and generally higher industry costs. Our average domestic lease and facility operating expenses are $0.65 per Mcfe in 2010 and $0.58 per Mcfe in 2009. The increase in the per unit amount results primarily from an increase in costs incurred to maintain individual well production rates and higher industry costs;

$53 million higher gathering, processing and transportation expenses, primarily as a result of processing fees charged by Williams Partners at its Willow Creek plant for extracting NGLs from a portion of our Piceance Basin gas production. Our domestic gathering, processing and transportation expenses averaged $0.80 per Mcfe in 2010 and $0.64 per Mcfe in 2009. The increase in the per unit amount is primarily a result of the Willow Creek plant going into service in August 2009 resulting in a partial year of processing. This processing provides us additional NGL recovery, the revenues for which are included in oil and gas sales in the Combined Statement of Operations;

$32 million higher taxes other than income, including severance and ad valorem, primarily due to higher average commodity prices (excluding the impact of hedges). Our domestic production taxes averaged $0.27 per Mcfe in 2010 and $0.19 per Mcfe in 2009. The increase in the per unit amount is primarily the result of higher average domestic commodity prices;

$276 million increase in gas management expenses, primarily due to an 18 percent increase in average prices on domestic physical natural gas cost of sales. This activity represents natural gas purchased in connection with our gas purchase activities for Williams Partners and certain working interest owners share of production, and to manage our transportation and storage activities. The sales associated with our marketing of this gas are included in gas management revenues. Also included in gas management expenses are $48 million in 2010 and $21 million in 2009 for unutilized pipeline capacity;

$19 million higher exploration expense primarily due to an increase in impairment, amortization and expiration of unproved leasehold costs; and

$1,681 million impairments of property and goodwill in 2010 as previously discussed. In 2009, $15 million of impairments were recorded in the Barnett Shale.

Partially offsetting the increased costs and expenses in 2010 are decreases due to the following:

$12 million lower depreciation, depletion and amortization expenses primarily due to lower domestic production volumes; and

Other net includes $32 million of expenses in 2009 related to penalties from the early release of drilling rigs.

The $1,654 million decrease in operating income (loss) is primarily due to the impairments, partially offset by a seven percent increase in domestic realized average prices on production and the other previously discussed changes in revenues and costs and expenses.

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Interest expense increased primarily due to higher average amounts outstanding under our unsecured notes payable to Williams.

Provision (benefit) for income taxes changed favorably due to the pre-tax loss in 2010 compared to pre-tax income in 2009. See Note 10 of Notes to Combined Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

2009 vs. 2008

The decrease in total revenues is primarily due to the following:

$714 million lower oil and gas sales revenues primarily from a $915 million decrease resulting from a 30 percent decrease in domestic realized average prices, partially offset by an increase of $194 million associated with a seven percent increase in domestic production volumes sold. Oil and gas revenues in 2009 and 2008 include approximately $136 million and $89 million, respectively, related to NGLs and approximately $38 million and $62 million, respectively, related to condensate. While NGL volumes were significantly higher than the prior year, NGL prices were significantly lower;

$1,785 million lower gas management revenues primarily from a 56 percent decrease in average prices on domestic physical natural gas sales associated with our transportation and storage contracts. There is a similar decrease of $1,753 million in related costs and expenses; and

$11 million lower hedge ineffectiveness and mark-to-market gains and losses primarily due to the absence of a $10 million favorable impact in 2008 for the initial consideration of our own nonperformance risk in estimating the fair value of our derivative liabilities.

The decrease in total costs and expenses is primarily due to the following:

$161 million lower taxes other than income, including severance and ad valorem, primarily due to 50 percent lower average commodity prices (excluding the impact of hedges), partially offset by higher production volumes sold. The lower operating taxes include a net decrease of $39 million reflecting a $34 million charge in 2008 and $5 million of favorable revisions in 2009 relating to Wyoming severance and ad valorem taxes. Our domestic production taxes averaged $0.19 per Mcfe in 2009 and $0.60 per Mcfe in 2008. The decrease in the per unit amount is primarily the result of lower average commodity prices;

$1,753 million decrease in gas management expenses, primarily due to a 55 percent decrease in domestic average prices on physical natural gas cost of sales, slightly offset by a 2 percent increase in natural gas sales volumes. This decrease is primarily related to the natural gas purchases associated with our previously discussed transportation and storage contracts and is more than offset by a decrease in revenues. Gas management expenses in 2009 and 2008 include $21 million and $8 million, respectively, related to charges for unutilized pipeline capacity. Gas management expenses in 2009 and 2008 also include $7 million and $35 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage; and

Partially offsetting the decreased costs and expenses are increases due to the following:

$44 million higher gathering, processing and transportation expense primarily due to higher production volumes and the processing fees for NGLs at Williams Partners   Willow Creek plant, which began processing in August 2009. Our domestic gathering, processing and transportation expenses averaged $0.64 per Mcfe in

2009 and $0.57 per Mcfe in 2008. The increase in the per unit amount is primarily a result of the initiation of processing at the Willow Creek plant in 2009 as previously discussed; and

$17 million higher exploration expense primarily due to an increase in geologic and geophysical services.

$149 million higher depreciation, depletion and amortization expense primarily due to higher capitalized drilling costs from prior years and higher production volumes compared to the prior year. Also, we recorded an additional $17 million of depreciation, depletion and amortization in the fourth

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quarter of 2009 primarily due to new SEC reserves reporting rules. Our proved reserves decreased primarily due to the new SEC reserves reporting rules and the related price impact;

The absence in 2009 of a $148 million gain recorded in 2008 from the sale of our contractual right to a production payment in Peru;

$32 million of expense in 2009 related to penalties from the early release of drilling rigs as previously discussed; and

$15 million of impairment expense in 2009 related to costs of acquired unproved reserves from our 2008 acquisition in the Barnett Shale. This impairment was based on our assessment of estimated future discounted cash flows and additional information obtained from drilling and other activities in 2009.

The $984 million decrease in operating income is primarily due to the 30 percent decrease in realized average domestic prices and the other previously discussed changes in revenues and costs and expenses.

Provision (benefit) for income taxes changed favorably primarily due to lower pre-tax income. See Note 10 of Notes to Combined Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

Management s Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2010, we continued to focus upon growth through continued disciplined investments in expanding our natural gas, oil and NGL portfolio. Examples of this growth included continued investment in our development drilling programs, as well as acquisitions that expanded our presence in the Marcellus Shale and provided our initial entry into the Bakken Shale areas. These investments were funded through cash flow from operations, advances on our notes payable from Williams and the proceeds from the sale of our Piceance Basin gathering and processing assets to Williams Partners.

Our historical liquidity needs have been managed through an internal cash management program with Williams. Daily cash activity from our domestic operations was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011 at which time the notes were cancelled by Williams. Any cash activity from July 1, 2011 has been or is expected to be treated as capital contributions until the earlier of the issuance of the Notes or this offering. In consideration of our liquidity under these conditions, we note the following:

As of September 30, 2011, Williams maintained liquidity through cash, cash equivalents and available credit capacity under credit facilities. Additionally, at that date we had an unsecured credit agreement that served to reduce our margin requirements related to our hedging activities. See additional discussion in the following Liquidity section.

Our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support.

Apco s liquidity requirements have historically been provided by its cash flows from operations.

Outlook

Upon completion of the issuance of the Notes and this offering, we expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures and tax and debt payments while maintaining a sufficient level of liquidity. We intend to retain approximately $500 million of the net proceeds from the issuance of the Notes and to distribute the remaining net proceeds, along with all of the net proceeds from this offering, to Williams. We also expect to have access to our new unsecured $1.5 billion Credit Facility that is expected to become effective prior to this offering. This Credit Facility combined with the $500 million in cash described above and our expected cash flows from operations should be sufficient to allow us to pursue our business strategy and goals for 2011 and 2012.

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If energy commodity prices are lower than we expect for 2011 and into 2012, we believe the effect on our cash flows from operations would be partially mitigated by our hedging program. In addition, we note the following assumptions for 2011 and 2012:

Our capital expenditures are estimated to be between $1.35 billion and $1.55 billion in 2011 and between $1.2 billion and $1.8 billion in 2012, and are generally considered to be largely discretionary; and

Apco s liquidity requirements will continue to be provided from its cash flows from operations and available liquidity under its credit facility.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

Sustained reductions in energy commodity prices from the range of current expectations;

Lower than expected levels of cash flow from operations;

Higher than expected collateral obligations that may be required, including those required under new commercial agreements; and

Significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold.

Liquidity

We plan to conservatively manage our balance sheet. Subsequent to this offering and the issuance of the Notes, we expect to maintain liquidity through a combination of cash on hand and available capacity under our $1.5 billion Credit Facility. In addition, we expect our forecasted levels of cash flow from operations to provide additional liquidity to assist us in meeting our desired level of capital expenditures and working capital requirements. Additional sources of liquidity, if needed, could be sought through bank financings, the issuance of long term debt and equity securities and proceeds from asset sales.

Currently we utilize an unsecured credit arrangement in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. This facility will be terminated prior to the effectiveness of our Credit Facility. Upon termination, we expect we will be able to negotiate agreements with the respective counterparties to our hedging contracts and keep margin requirements, if any, to a minimum.

We have certain contractual obligations, primarily interstate transportation agreements, which contain collateral support requirements based on our credit ratings. Because Williams has an investment grade credit rating and guaranteed these contracts, we have not historically been required to provide collateral support. After the completion of this offering, Williams has informed us that it expects it will obtain releases of the guarantees. Depending on our credit rating, we anticipate issuing letters of credit under our Credit Facility of $285 million to satisfy the provisions of these contracts but the amount could be up to approximately $500 million.

Our ability to borrow money will be impacted by several factors, including our credit ratings. Credit ratings agencies perform independent analysis when assigning credit ratings. A lower than anticipated initial credit rating or a downgrade of that rating would increase our future cost of borrowing and could result in a requirement that we post additional collateral with third parties, thereby negatively affecting our available liquidity.

Williams has agreed to provide us with up to a maximum amount of $20 million with respect to certain information technology transition costs we will incur as a result of our separation from Williams. The actual amount of cash we receive from Williams for these costs at the completion of this offering will be reduced by the total amount of such information technology costs already funded by Williams in advance of this offering. As of September 30, 2011, Williams had incurred approximately $2 million related to these costs, resulting in a remaining potential reimbursement of up to approximately $18 million. The entire amount we receive from Williams will be recorded as a capital contribution from Williams upon receipt and any future amounts we spend on such information technology transition costs and expenses will be recorded as increases in our assets or expenses depending on the specific nature of the costs.

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Sources (Uses) of Cash

Nine Months-Over-Nine Months

The following table and discussion summarize our sources (uses) of cash for the nine months ended September 30, 2011 and 2010.

	Nine Months Ended September 30,	
	2011	2010
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 888	$ 852
Investing activities	(1,056)	(1,433)
Financing activities	181	582
Increase in cash and cash equivalents	$ 13	$ 1

Operating activities

Our net cash provided by operating activities in 2011 increased from 2010 primarily due to net changes in our operating assets and liabilities partially offset by higher operating costs, primarily gathering, processing and transportation costs and higher interest expense.

Investing activities

Our net cash used by investing activities in 2011 decreased from 2010 primarily due to reduced capital expenditures. During the third quarter of 2010, we acquired approximately $599 million of properties in the Marcellus Shale. Expenditures for drilling and completion were $982 million in 2011 and $662 million in 2010.

Financing activities

Our net cash provided by financing activities in 2011 decreased from 2010 primarily due to reduced required funding from our parent of our capital expenditures that were in excess of cash provided by operating activities in 2011. In 2011, we also incurred $8 million of revolving debt facility costs that relate to the $1.5 billion Credit Facility that is expected to become effective prior to the time this offering is completed.

Year-Over-Year

The following table and discussion summarize our sources (uses) of cash for the years ended December 31, 2010, 2009 and 2008.

	Years Ended December 31,		
	2010	2009	2008
	(Millions)		

Net cash provided (used) by:			
Operating activities	$ 1,056	$ 1,181	$ 2,009
Investing activities	(2,337)	(1,435)	(2,252)
Financing activities	1,284	256	225
Increase (decrease) in cash and cash equivalents	$ 3	$ 2	$ (18)

Operating activities

Our net cash provided by operating activities in 2010 decreased from 2009 primarily due to the payments made to reduce certain accrued liabilities affecting our operations.

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Our net cash provided by operating activities in 2009 decreased primarily due to the lower realized energy commodity prices during 2009 when compared to 2008.

Investing activities

Our net cash used by investing activities in 2010 increased from 2009 primarily due to our capital expenditures related to the acquisition of Marcellus Shale properties and our entry into the Bakken Shale.

Significant expenditures include:

2010

Expenditures for drilling and completion were approximately $950 million.

Our acquisition in July 2010 of properties in the Marcellus Shale for $599 million (see Overview of 2010).

Our acquisition in December 2010 of oil and gas properties in the Bakken Shale for $949 million (see Overview of 2010).

The sale in November 2010 of certain gathering and processing assets in the Piceance Basin to Williams Partners for $702 million in cash and approximately 1.8 million Williams Partners common units, which units were subsequently distributed to Williams.

2009

Expenditures for drilling and completion were approximately $1.0 billion.

A $253 million payment for the purchase of additional properties in the Piceance Basin.

2008

Expenditures for drilling and completion were approximately $1.65 billion.

Acquisitions of certain interests in the Piceance Basin for $285 million. A third party subsequently exercised its contractual option to purchase a 49 percent interest in a portion of the acquired assets for $71 million.

Our sale of a contractual right to a production payment in Peru for $148 million.

Financing activities

Our net cash provided by financing activities in 2010 increased from 2009 primarily due to higher borrowings from Williams to fund our capital expenditures, including those related to the acquisition of Marcellus Shale properties and our acquisition in the Bakken Shale.

Off-Balance Sheet Financing Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at September 30, 2011 and December 31, 2010.

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Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at September 30, 2011, including obligations related to discontinued operations.

	October 1 - December 31, 2011	2012 - 2013	2014 - 2015 (Millions)	Thereafter	Total
Long-term debt	$	$ 2	$	$	$ 2
Operating leases and associated service commitments					
Drilling rig commitments(1)	40	248	147		435
Other	3	16	13	41	73
Transportation and storage commitments(2)	53	427	343	633	1,456
Natural gas purchase commitments(3)	23	306	435	1,096	1,860
Oil and gas activities(4)	75	383	164	270	892
Other long-term liabilities, including current portion:					
Physical and financial derivatives(5)(6)	162	967	810	3,524	5,463
Total	$ 356	$ 2,349	$ 1,912	$ 5,564	$ 10,181

(1) Includes materials and services obligations associated with our drilling rig contracts.

(2) Excludes additional commitments totaling $240 million associated with projects for which the counterparty has not yet received satisfactory regulatory approvals.

(3) Purchase commitments are at market prices and the purchased natural gas can be sold at market prices. The obligations are based on market information as of September 30, 2011 and contracts are assumed to remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur. Certain parties have elected to convert their gas purchase agreements to firm gathering and processing agreements, which services will be provided by an affiliate of ours. WPX Energy s gas purchase obligations amounting to $1.9 billion will terminate at the effective date of the new agreements.

(4) Includes gathering, processing and other oil and gas related services commitments. Excluded are liabilities associated with asset retirement obligations, which total $301 million as of September 30, 2011. The ultimate settlement and timing can not be precisely determined in advance; however, we estimate that approximately 10% of this liability will be settled in the next five years.

(5) Includes $4.9 billion of physical natural gas derivatives related to purchases at market prices. The natural gas expected to be purchased under these contracts can be sold at market prices, largely offsetting this obligation. The obligations for physical and financial derivatives are based on market information as of September 30, 2011,

and assume contracts remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur.

(6) Expected offsetting cash inflows of $3.9 billion at September 30, 2011, resulting from product sales or net positive settlements, are not reflected in these amounts. In addition, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

Effects of Inflation

Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy. Operating costs are influenced by both competition for specialized services and specific price changes in natural gas, oil, NGLs and other commodities. We tend to experience inflationary pressure on the cost of services and equipment as increasing oil and gas prices increase drilling activity in our areas of operation.

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Environmental

We are subject to the Clean Air Act (CAA) and to the Clean Air Act Amendments of 1990 (1990 Amendments), which added significantly to the existing requirements established by the CAA. Pursuant to requirements of the 1990 Amendments and EPA rules designed to mitigate the migration of ground-level ozone (NOx), we are planning installation of air pollution controls on existing sources at certain facilities in order to reduce NOx emissions. For many of these facilities, we are developing more cost effective and innovative compressor engine control designs.

In March 2008, the EPA promulgated a new, lower National Ambient Air Quality Standard (NAAQS) for NOx. In January 2010, the EPA issued a revised proposal; however, it withdrew the proposed rule on September 2, 2011. Under the CAA, the EPA will be required to review and potentially issue a new NAAQS for ground-level NOx in 2013. Designation of new eight-hour ozone non-attainment areas may result in additional federal and state regulatory actions that could impact our operations and increase the cost of additions to property, plant and equipment net on the Combined Balance Sheet. We are unable at this time to estimate the cost of additions that may be required to meet this future regulation.

In August 2011, the EPA stated that the proposed PM (particulate matter) NAAQS will be issued in 2011. This rule may result in increased capital expenditures and operating costs, and could adversely impact our business.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s proposed rule includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules also would establish specific new requirements regarding emissions from wells (including well completions at new hydraulically fractured natural gas wells and re-completions of existing wells that are fractured or re-fractured), compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on the rules by April 3, 2012. If finalized as written, these rules could require modifications to our operations including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Additionally, in August 2010, the EPA promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations that will impact our operations. Furthermore, the EPA promulgated the Greenhouse Gas (GHG) Mandatory Reporting Rule on October 30, 2009, which requires facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year from stationary fossil fuel combustion sources to report GHG emissions to the EPA annually beginning September 30, 2011 for calendar year 2010. On November 30, 2010, the EPA issued additional regulations that expand the scope of the Mandatory Reporting Rule to include fugitive and vented greenhouse gas emissions effective January 1, 2011. Facilities that emit 25,000 metric tons or more carbon dioxide equivalent per year from stationary fossil-fuel combustion and fugitive/vented sources combined will be required to report GHG combustion and fugitive/vented emissions to the EPA annually beginning March 31, 2012, for calendar year 2011.

In February 2010, the EPA promulgated a final rule establishing a new one-hour nitrogen dioxide NAAQS. The effective date of the new nitrogen dioxide standard was April 12, 2010. This new standard is subject to numerous challenges in the federal court. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

Our facilities and operations are also subject to the Clean Water Act (CWA) and implementing regulations of the EPA and the U.S. Army Corps of Engineers (Corps). On April 27, 2011, the EPA and the Corps released new draft guidance governing federal jurisdiction over wetlands and other isolated waters. They would, if adopted, significantly expand federal jurisdiction and permitting requirements under the CWA. Additionally, the draft guidance addresses the expanded scope of the CWA s key term waters of the United

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States to all CWA provisions, which prior guidance limited to Section 404 determinations. We are unable at this time to estimate the cost that may be required to meet this proposed guidance.

Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Historically, our current interest rate risk exposure was substantially mitigated through our cash management program and the effects of our intercompany note with Williams. The Notes will be fixed rate debt in order to mitigate the impact of fluctuations in interest rates and we expect that any borrowings under our Credit Facility could be at a variable interest rate and could expose us to the risk of increasing interest rates. See Note 4 of Notes to Combined Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, NGLs and crude oil, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Note 15 of Notes to Combined Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of $1 million at September 30, 2011 and a net asset of $2 million at December 31, 2010. The value at risk for contracts held for trading purposes was less than $1 million at September 30, 2011, December 31, 2010 and December 31, 2009.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $9 million and $16 million at September 30, 2011 and December 31, 2010, respectively.

The value at risk for derivative contracts held for nontrading purposes was $21 million at September 30, 2011, $24 million at December 31, 2010, and $34 million at December 31, 2009. During the year ended December 31, 2010, our value at risk for these contracts ranged from a high of $33 million to a low of $21 million. The decrease in value at risk from December 31, 2009 primarily reflects the realization of certain derivative positions and the market price impact, partially offset by new derivative contracts.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $316 million and $266 million as of September 30, 2011 and December 31, 2010, respectively. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

In our management s opinion, the more significant reporting areas impacted by management s judgments and estimates are impairments of goodwill and long-lived assets, accounting for derivative instruments and hedging activities, successful efforts method of accounting, contingent liabilities, valuation of deferred tax assets and tax contingencies.

Impairments of Goodwill and Long-Lived Assets

We have assessed goodwill for impairment annually as of the end of the year and we have performed interim assessments of goodwill if impairment triggering events or circumstances were present. One such triggering event is a significant decline in forward natural gas prices. Early in 2010, we evaluated the impact of declines in forward gas prices across all future production periods and determined that the impact was not significant enough to warrant a full impairment review. Forward natural gas prices through 2025 used in these prior analyses had declined less than 10 percent, on average, from December 31, 2009 through March 31, 2010 and June 30, 2010. During the third quarter of 2010, these forward natural gas prices through 2025 declined an additional 19 percent for a total year-to-date decline of more than 22 percent on average through September 30, 2010. Based on forward prices as of September 30, 2010, we evaluated the impact of this decline across all future production periods and determined that a full impairment review was warranted.

As a result, we evaluated our goodwill of approximately $1 billion resulting from a 2001 acquisition related to our domestic natural gas production operations (the reporting unit). Our impairment evaluation of goodwill first considered management s estimate of the fair value of the reporting unit compared to its carrying value, including goodwill. If the carrying value of the reporting unit exceeded its fair value, a computation of the implied fair value of the goodwill was compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeded the implied fair value of that goodwill, an impairment loss was recognized in the amount of the excess. Because quoted market prices were not available for the reporting unit, management applied reasonable judgments (including market supported assumptions when available) in estimating the fair value for the reporting unit. We estimated the fair value of the reporting unit on a stand-alone basis and also considered Williams market capitalization and third party estimates in corroborating our estimate of the fair value of the reporting unit.

The fair value of the reporting unit was estimated primarily by valuing proved and unproved reserves. We use an income approach (discounted cash flows) for valuing reserves, based on inputs we believed would be utilized by market participants. The significant inputs into the valuation of proved and unproved reserves include reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired.

In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its fair value. We then determined that the implied fair value of the goodwill was zero. As a result, we recognized a full $1 billion impairment charge related to our goodwill. See Notes 6 and 14 of Notes to Combined Financial Statements for additional discussion and significant inputs into the fair value determination.

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the estimated fair value of the asset, undiscounted future cash flows, discounted future cash flows and the current and future economic environment in which the asset is operated.

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we assessed our natural gas producing properties and acquired unproved reserve costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. The assessment performed at September 30, 2010 identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recognized a $678 million impairment charge. See Notes 6 and 14 of Notes to Combined Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included our other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the combined financial statements. For certain other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately 12 percent could be at risk for impairment if forward prices across all future periods decline by approximately 8 to 12 percent, on average, as compared to the forward prices at December 31, 2010. A substantial portion of the remaining carrying value of these other assets (primarily related to our assets in the Piceance Basin) could be at risk for impairment if forward prices across all future periods decline by at least 30 percent, on average, as compared to the prices at December 31, 2010.

As of September 30, 2011, the impact of changes in forward prices since December 31, 2010 to our cash flow estimates was indicative of a potential impairment. As a result, we conducted an impairment review of our proved producing oil and gas properties in the Powder River Basin as of September 30, 2011. The net book value of our proved producing assets in the Powder River Basin was approximately $500 million at September 30, 2011. The recording of an impairment charge was not required as of September 30, 2011, as the undiscounted cash flows were greater than the net book value. Our interim impairment assessment included not only a review of forward pricing assumptions but also consideration of other factors impacting estimated future net cash flows, including but not limited to reserve and production estimates, future operating costs, future development costs and production taxes. Our 2011 interim updated reserve estimates for Powder River included 2011 additions to proved reserves. In this interim assessment, we noted that the Powder River producing assets could be at risk of impairment if the weighted average forward price across all periods used in our cash flow estimates were to decline by approximately six percent on average, absent changes in other factors. These properties will be part of our annual impairment assessment in the fourth quarter and could be subject to impairment. If the recording of an impairment charge becomes necessary for these properties as of December 31, 2011, it is reasonably possible that the amount of such charge could be at least $200 million.

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Accounting for Derivative Instruments and Hedging Activities

We review our energy contracts to determine whether they are, or contain, derivatives. Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short-term, with more than 99 percent of the value of our derivatives portfolio expiring in the next 24 months. We further assess the appropriate accounting method for any derivatives identified, which could include:

- qualifying for and electing cash flow hedge accounting, which recognizes changes in the fair value of the derivative in other comprehensive income (to the extent the hedge is effective) until the hedged item is recognized in earnings;

- qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or

- applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings.

If cash flow hedge accounting or accrual accounting is not applied, a derivative is subject to mark-to-market accounting. Determination of the accounting method involves significant judgments and assumptions, which are further described below.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in offsetting the cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives designated as cash flow hedges, we must periodically assess whether they continue to qualify for hedge accounting. We prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclassify amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting the cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

Since our energy derivative contracts could be accounted for in three different ways, two of which are elective, our accounting method could be different from that used by another party for a similar transaction.

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Furthermore, the accounting method may influence the level of volatility in the financial statements associated with changes in the fair value of derivatives, as generally depicted below:

	Combined Statement of Operations		Combined Balance Sheet	
Accounting Method	**Drivers**	**Impact**	**Drivers**	**Impact**
Accrual Accounting	Realizations	Less Volatility	None	No Impact
Cash Flow Hedge Accounting	Realizations & Ineffectiveness	Less Volatility	Fair Value Changes	More Volatility
Mark-to-Market Accounting	Fair Value Changes	More Volatility	Fair Value Changes	More Volatility

Our determination of the accounting method does not impact our cash flows related to derivatives.

Additional discussion of the accounting for energy contracts at fair value is included in Notes 1 and 14 of Notes to Combined Financial Statements.

Successful Efforts Method of Accounting for Oil and Gas Exploration and Production Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates; and

- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, approximately 94 percent of our domestic reserve estimates are audited by independent experts. The data may change substantially over time as a result of numerous factors, including additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. Such changes could trigger an impairment of our oil and gas properties and have an impact on our depreciation, depletion and amortization expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual depreciation, depletion and amortization expense between approximately $76 million and $93 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserve categories.

Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the forward price curve could result in an impairment of our oil and gas properties.

We record the cost of leasehold acquisitions as incurred. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. Changes in our assumptions regarding the estimates of the nonproductive portion of these leasehold acquisitions could result in impairment of these costs. Upon determination that specific acreage will not be developed, the costs associated with that acreage would be impaired.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 11 of Notes to Combined Financial Statements.

Valuation of Deferred Tax Assets and Liabilities

Our domestic operations are included in the consolidated and combined federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision has been calculated on a separate return basis, which requires judgment in computing a stand-alone effective state tax rate as we did not exist as a stand-alone filer during these periods and can change periodically based on our operations. If the effective state tax rate were to be revised upward by one percent, this would result in an increase to our net deferred income tax liability of approximately $33 million.

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of book basis and from certain separate state losses generated in the current and prior years. We must evaluate whether we will ultimately realize these tax benefits and establish a valuation allowance for those that may not be realizable. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. When assessing the need for a valuation allowance, we consider forecasts of future company performance, the estimated impact of potential asset dispositions, and our ability and intent to execute tax planning strategies to utilize tax carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets. For example, Williams manages its tax position based upon its entire portfolio, which may not be indicative of tax planning strategies available to us if we were operating as an independent company.

See Note 10 of Notes to Combined Financial Statements for additional information.

Fair Value Measurements

A limited amount of our energy derivative assets and liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At December 31, 2010, less than 1 percent of our energy derivative assets and liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2010, the credit reserve is less than $1 million on both on our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2010, 89 percent of the fair value of our derivatives portfolio expires in the next 12 months and more than 99 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2010, consist of natural gas index transactions that are used to manage the physical requirements of our business. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices during the month of delivery. There are generally no active forward markets or quoted prices for natural gas index transactions.

We have an unsecured credit agreement through December 2015 with certain banks that, so long as certain conditions are met, serves to reduce our usage of cash and other credit facilities for margin requirements related to instruments included in the facility. We anticipate this agreement will be dissolved and individual contracts will be executed with the same banks under similar margining requirements. See further discussion in Management s Discussion and Analysis of Financial Condition and Liquidity.

For the years ended December 31, 2010 and 2009, we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. See Note 14 of Notes to Combined Financial Statements.

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BUSINESS

Overview

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserve base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our positions in the Bakken Shale oil play in North Dakota and the Marcellus Shale natural gas play in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco, which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol APAGF. Our international interests make up approximately five percent of our total proved reserves. In consideration of this percentage, unless specifically referenced herein, the information included in this section relates only to our domestic activity.

We have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. For the five years ended December 31, 2010, we have grown production at a compound annual growth rate of 12 percent. As of December 31, 2010, our proved reserves were 4,473 Bcfe, 59 percent of which were proved developed reserves. Average daily production for the month of September 2011 was 1,374 MMcfe/d. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

The following table provides summary data for each of our primary areas of operation as of December 31, 2010, unless otherwise noted.

	Estimated Net Proved Reserves		September 2011 Average Daily Net			2011 Budget Estimate	
Basin/Shale	Bcfe	% Proved Developed	Production (MMcfe/d)(1)	Net Acreage	Gross Wells	Drilling Capital(2) (Millions)	PV-10(3) (Millions)
Piceance Basin	2,927	53%	806	211,000	376	$ 575	$ 2,707
Bakken Shale(4)	136	11%	36	89,420	41	260	399
Marcellus Shale	28	71%	16	99,301	62	170	29
Powder River Basin	348	75%	235	425,550	411	70	317
San Juan Basin	554	79%	145	120,998	51	40	477
Apco(5)	190	60%	54	404,304	37	30	358
Other(6)	290	72%	82	327,390	94	85	257
Total	4,473	59%	1,374	1,677,963	1,072	$ 1,230	$ 4,544

(1) Represents average daily net production of our continuing operations for the month of September 2011.

(2) Based on the midpoint of our estimated capital spending range.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. For a definition of PV-10 and a reconciliation of PV-10 to Standardized Measure, see Prospectus Summary Summary Combined Historical Operating and Reserve Data Non-GAAP Financial Measures and Reconciliations.

(4) Our estimated net proved reserves in the Bakken Shale have not been audited by independent reserve engineers.

(5) Represents approximately 69 percent of each metric (which corresponds to our ownership interest in Apco) except Percent Proved Developed, Gross Wells and Drilling Capital.

(6) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties. September 2011 average daily net production excludes Arkoma production of approximately nine MMcfe/d as our Arkoma Basin operations were classified as held for sale and reported as discontinued operations as of June 30, 2011.

2011 Capital Expenditures Budget

Our total 2011 capital expenditures budget is expected to be between \$1.35 billion and \$1.55 billion, and will consist of the following, representing the midpoint of this range:

- approximately \$1.23 billion for development drilling; and
- approximately \$0.22 billion for facilities, infrastructure, and land/acquisitions.

While we have budgeted between \$1.35 billion and \$1.55 billion of capital deployment in 2011, the ultimate amount and allocation of capital spent in 2011 could vary. We will evaluate market conditions in each of our operating areas to determine the estimated economic returns on capital employed. If those returns exceed or fall short of our thresholds, our capital expenditures and allocations could change accordingly. In addition, we believe that after completion of this offering we will be well positioned to pursue large scale strategic acquisitions that are not included in our 2011 capital expenditures budget. However, our ability to enter into corporate transactions will be subject to certain restrictions. For example, prior to the spin-off, we may not enter into transactions that would reduce Williams ownership to less than 80% of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors or less than 80% of the then outstanding shares of any class of non-voting stock. Similarly, after the spin-off, we may not enter into transactions that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock taking into account shares issued in this offering in transactions considered related to the spin-off. These restrictions are necessary in order to maintain the tax-free treatment of our separation from Williams. See Risk Factors Risks Related to our Relationship with Williams Our agreements with Williams may limit our ability to obtain additional financing or make acquisitions, and Risk Factors Risks Related to our Relationships with Williams Our tax sharing agreement with Williams may limit our ability to take certain actions and may require us to indemnify Williams for significant tax liabilities.

Our Business Strategy

Our business strategy is to increase shareholder value by finding and developing reserves and producing natural gas, oil and NGLs at costs that generate an attractive rate of return on our investment.

- *Efficiently Allocate Capital for Optimal Portfolio Returns.* We expect to allocate capital to the most profitable opportunities in our portfolio based on commodity price cycles and other market conditions, enabling us to continue to grow our reserves and production in a manner that maximizes our return on investment. In determining which drilling opportunities to pursue, we target a minimum after-tax internal rate of return on each operated well we drill of 15 percent. While we have a significant portfolio of drilling opportunities that we believe meet or exceed our return targets even in challenging commodity price environments, we are disciplined in our approach to capital spending and will adjust our drilling capital expenditures based on our level of expected cash flows, access to capital and overall liquidity position. For example, in 2009 we demonstrated our capital discipline by reducing drilling expenditures in response to prevailing commodity prices and their impact on these factors.

Continue Our Cost-Efficient Development Approach. We focus on developing properties where we can apply development practices that result in cost-efficiencies. We manage costs by focusing on establishing large scale, contiguous acreage blocks where we can operate a majority of the properties. We believe this strategy allows us to better achieve economies of scale and apply continuous technological improvements in our operations. We intend to replicate these cost-efficient approaches in our recently acquired growth positions in the Bakken Shale and the Marcellus Shale.

Pursue Strategic Acquisitions with Significant Resource Potential. We have a history of acquiring undeveloped properties that meet our disciplined return requirements and other acquisition criteria to expand upon our existing positions as well as acquiring undeveloped acreage in new geographic areas that offer significant resource potential. This is illustrated by our recent acquisitions in the Bakken Shale and the Marcellus Shale. We seek to continue expansion of current acreage positions and opportunistically acquire acreage positions in new areas where we feel we can establish significant scale and replicate our cost-efficient development approach.

Target a More Balanced Commodity Mix in Our Production Profile. With our Bakken Shale acquisition in December 2010 and our liquids-rich Piceance Basin assets, we have a significant drilling inventory of oil- and liquids-rich opportunities that we intend to develop rapidly in order to achieve a more balanced commodity mix in our production. We refer to the Piceance Basin as liquids-rich because our proved reserves in that basin consist of wet, as opposed to dry, gas and have a significant liquids component. Our current estimated proved reserves of NGLs and condensate in the Piceance Basin are 95 MMbbl and 3 MMbbl, respectively. We will continue to pursue other oil- and liquids-rich organic development and acquisition opportunities that meet our investment returns and strategic criteria.

Maintain Substantial Financial Liquidity and Manage Commodity Price Sensitivity. We plan to conservatively manage our balance sheet and maintain substantial liquidity through a mix of cash on hand and availability under our Credit Facility. In addition, we have engaged and will continue to engage in commodity hedging activities to maintain a degree of cash flow stability. Typically, we target hedging approximately 50 percent of expected revenue from domestic production during a current calendar year in order to strike an appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. At September 30, 2011, our estimated domestic natural gas production revenues were 67 percent hedged for 2011 and 48 percent hedged for 2012. Estimated domestic oil production revenues were 48 percent hedged for 2011 and 49 percent hedged for 2012 as of the same date.

Our Competitive Strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

A Leading Piceance Basin Cost Structure. We have a large position in the lower cost valley area of the Piceance Basin, which we believe provides us economies associated with lower elevation drilling and large contiguous operations, allowing us to continuously drive down operating costs and increase efficiencies. The existing substantial midstream infrastructure in the Piceance Basin contributes to our cost-efficient structure and provides take-away capacity for our natural gas and NGLs. Because of this cost-efficient structure in the Piceance Basin, we have the ability to generate returns that we believe are in excess of those typically associated with Rockies producers.

Attractive Asset Base Across a Number of High Growth Areas. In addition to our large scale Piceance Basin properties, our assets include emerging, high growth opportunities such as our Bakken Shale and Marcellus Shale positions. Based on our subsurface geological and engineering analysis of available well data, we believe our Bakken Shale and Marcellus Shale positions are located in core areas of these plays, which have associated historic drilling results that we believe offer highly attractive economic returns.

Extensive Drilling Inventory. As of December 31, 2010, we have identified approximately 2,900 proved undeveloped drilling locations. We have budgeted drilling approximately 500 gross operated wells during

2011. We have established significant scale in each of our core areas of operation that support multi-year development plans and allow us to optimally leverage our cost-efficient development approach. Our drilling inventory provides opportunities across diverse geographic markets and products including natural gas, oil and NGLs.

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Significant Operating Flexibility. In the Piceance Basin, Bakken Shale and Marcellus Shale, our three primary basins, we operate substantially all of our production. We expect approximately 91 percent of our projected 2011 domestic drilling capital will be spent on projects we operate. We believe acting as operator on our properties allows us to better control costs and capital expenditures, manage efficiencies, optimize development pace, ensure safety and environmental stewardship and, ultimately, maximize our return on investment. As operator, we are also able to leverage our experience and expertise across all basins and transfer technology advances between them as applicable. In addition, substantially all of our Piceance Basin properties are held by producing wells, which allows us to adjust our level of drilling activity in response to changing market conditions.

Significant Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. Immediately following the completion of this offering, we expect to have $2.0 billion of liquidity, comprised of availability under our $1.5 billion Credit Facility and approximately $500 million of cash on hand. We believe our pro forma level of debt to proved reserves is low relative to a majority of other publicly traded, independent oil and gas producers.

Management Team with Broad Unconventional Resource Experience. Our management and operating team has significant experience acquiring, operating and developing natural gas and oil reserves from tight-sands and shale formations. Our Chief Executive Officer and his direct reports have in excess of 238 collective years of experience running large scale drilling programs and drilling vertical and horizontal wells requiring complex well design and completion methods. Our team has demonstrated the ability to manage large scale operations and apply current technological successes to new development opportunities. We have deployed members of our successful Piceance Basin, Powder River Basin and Barnett Shale teams to the Bakken Shale and Marcellus Shale teams to help replicate our cost-efficient model and to apply our highly specialized technical expertise in the development of those resources.

Our Recent Acquisition History

An important part of our strategy to grow our business and enhance shareholder value is to acquire properties complementary to our existing positions as well as undeveloped acreage with significant resource potential in new geographic areas. Following is a summary of selected recent acquisitions in the Bakken Shale, Marcellus Shale and Piceance Basin.

Bakken Shale

In December 2010, we acquired Dakota-3 E&P Company LLC, a company that holds approximately 85,800 net acres on the Fort Berthold Indian Reservation in the Williston Basin, with then-current net oil production of 3,300 barrels per day from 24 existing wells, for $949 million.

Marcellus Shale

In July 2010, we acquired 42,000 net acres of largely undeveloped properties primarily located in Susquehanna County in northeastern Pennsylvania for $599 million.

During 2010, we also acquired additional unproved leasehold acreage positions in the Marcellus Shale for a total of $164 million.

In June 2009, we initiated our strategy of securing acreage in the Marcellus Shale with our participation and exploration agreement to develop natural gas wells with Rex Energy Corporation. We acquired a 50 percent interest in 44,000 net acres in Pennsylvania s Westmoreland, Clearfield and Centre Counties for $33 million in a drill to earn structure.

Piceance Basin

In September 2009, we completed a bolt-on acquisition of 21,800 net acres in the Piceance Basin, east of our existing properties, for $253 million. The asset included then current production of 24 MMcfe/d from 28 wells, related gas and water gathering facilities, 94 approved drilling permits and more than 800 drillable locations at 10-acre spacing. In December 2009, we increased our working interest in these properties through an additional $22 million acquisition.

In May 2008, we acquired 24,000 net acres in the Piceance Basin for $285 million. The acreage covered by the agreement was contiguous to our existing position in the Ryan Gulch area of the Piceance Basin Highlands in Rio Blanco County. A third party subsequently exercised its contractual option to purchase a 49 percent interest in a portion of the acquired assets for $71 million.

Recent Sales & Dispositions

In November 2010, we sold certain of our gathering and processing assets in Colorado s Piceance Basin to Williams Partners for $702 million in cash and approximately 1.8 million Williams Partners common units, which units were subsequently distributed to Williams. These assets include the Parachute Plant Complex, three other treating facilities with a combined processing capacity of 1.2 Bcf/d, and a gathering system with approximately 150 miles of pipeline. There are more than 3,300 wells connected to the gathering system, which includes pipelines ranging up to 30-inch trunk lines. As part of this sale, we agreed to continue to use this gathering system for our production in this area for the life of our leases. See Other Related Party Transactions Agreements Related to the Piceance Disposition.

In January 2008, we sold a contractual right to a production payment on certain future hydrocarbon production in Peru for $148 million. As a result of the contract termination, we have no further interests associated with this crude oil concession, which we had obtained through our acquisition of Barrett Resources Corporation in 2001.

Significant Properties

Our principal areas of operation are the Piceance Basin, Bakken Shale, Marcellus Shale, Powder River Basin, San Juan Basin and, through our ownership of Apco, Colombia and Argentina. A map of our properties within these geographic areas and our other properties can be found on the inside cover of this prospectus.

Piceance Basin

We entered the Piceance Basin in May 2001 with the acquisition of Barrett Resources and since that time have grown to become the largest natural gas producer in Colorado. Our Piceance Basin properties currently comprise our largest area of concentrated development drilling.

For the month of September 2011, we had an average of 806 MMcfe/d of net production from our Piceance Basin properties. Approximately 25 million gallons of NGLs are currently recovered each month from our Piceance Basin properties. A large majority of our natural gas production in this basin currently is gathered through a system owned by Williams Partners and delivered to markets through a number of interstate pipelines. See Other Related Party Transactions Gathering, Processing and Treating Contracts. As of December 31, 2010, our properties in the Piceance Basin included:

211,000 total net acres, including 108,165 undeveloped net acres;

2,927 Bcfe of estimated net proved reserves;

3,587 net producing wells; and

1,567 undrilled proved drilling locations.

During 2010, we operated an average of 11 drilling rigs in the basin, including nine in the Piceance Valley and two in the Piceance Highlands. As of September 30, 2011 we were operating 11 rigs and have an average of 11 rigs budgeted for 2011. We have allocated approximately $575 million in capital expenditures to drill 376 gross wells on our Piceance Basin properties in 2011.

The Piceance Basin is located in northwestern Colorado. Our operations in the basin are divided into two areas: the Piceance Valley and the Piceance Highlands. Our Piceance Valley area includes operations along the

Colorado River valley and is the more developed area where we have produced consistent, repeatable results. The Piceance Highlands, which are those areas at higher elevations above the river valley, contain vast development opportunities that position us well for growth in the future as infrastructure expands and efficiency improvements continue. Our development activities in the basin are primarily focused on the Williams Fork section within the Mesaverde formation. The Williams Fork can be over 2,000 feet in thickness and is comprised of several tight, interbedded, lenticular sandstone lenses encountered at depths ranging from 7,000 to 13,000 feet. In order to maximize producing rates and recovery of natural gas reserves we must hydraulically fracture the well using a fluid system comprised of 99 percent water and sand. Advancements in completion technology, including the use of microseismic data have enabled us to more effectively stimulate the reservoir and recover a greater percentage of the natural gas in place. We are currently evaluating deeper horizons such as the Mancos and Niobrara shale formations, which have the potential to provide additional development opportunities.

Initial development of the Piceance Basin was limited to conventional drilling and completion techniques. In response to the unique challenges posed by the geology of this area, we collaborated with our drilling contractors to build fit-for-purpose type drilling rigs, and beginning in 2005, were the first operator to introduce these types of drilling rigs to the Piceance Basin. Utilizing advancements in drilling technology and several innovative modifications, these special purpose rigs are capable of drilling 22 wells from a single well pad, drilling faster and extending the directional length of our wells, and can accommodate completion and production activities simultaneously. In addition to reducing surface impacts, these rigs are quieter, safer to operate, and have allowed us to significantly reduce cycle times from spud to spud and getting our gas to market. We have pioneered several other innovative practices such as green completions, which essentially eliminate gas flaring and emissions during completion operations, and using a clustered plan of development approach taking advantage of centralized facilities, as well as allowing us to fracture stimulate wells from over two miles away from the pumping equipment. In addition, all of our producing wells and associated facilities are fully automated and utilize our state-of-the art telemetry system, which provides our well technicians with real time data to ensure we are optimizing well performance. Our innovative approaches to drilling in the Piceance Basin have earned us positive state and federal recognition.

Bakken Shale

In December 2010 we acquired approximately 85,800 net acres in the Williston Basin. All of our properties in the Williston Basin are on the Fort Berthold Indian Reservation in North Dakota, where we will be the primary operator. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results as well as the publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation, the primary target for all of the well locations in our current drilling inventory.

For the month of September 2011, we had an average of 6.0 Mboe/d of net production from our Bakken Shale wells. As of December 31, 2010, our properties in the Bakken Shale included:

- 89,420 total net acres, including 75,937 undeveloped net acres;
- 23 MMboe of estimated net proved reserves; and
- 13 net producing wells.

As of September 30, 2011 we were operating four rigs and plan to add an additional rig during 2011. We have allocated approximately $260 million in capital expenditures to drill 41 gross wells on our Bakken Shale properties in 2011.

We plan to develop oil reserves through horizontal drilling from both the Middle Bakken and Upper Three Forks shale oil formations utilizing drilling and completion expertise gained in part through experience in our other basins. Based on our subsurface geological analysis, we believe that our position lies in the area of the basin s greatest potential recovery for Bakken formation oil. Currently our Bakken Shale development has the highest incremental returns of any of our drilling programs.

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The Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada, covering approximately 202,000 square miles, of which 143,000 square miles are in the United States. The basin produces oil and natural gas from numerous producing horizons including the Bakken, Three Forks, Madison and Red River formations. A report issued by the U.S. Geological Survey in April 2008 classified the Bakken formation as the largest continuous oil accumulation ever assessed by it in the contiguous United States.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members referred to as the Upper, Middle and Lower Bakken shales. The formation ranges up to 150 feet thick and is a continuous and structurally simple reservoir. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The Middle Bakken, which varies in composition from a silty dolomite to shaly limestone or sand, serves as the productive formation and is a critical reservoir for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock that may add incremental reserves to our existing leasehold positions. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation has recently been exploited utilizing the same horizontal drilling and advanced completion techniques as the Bakken development. Drilling in the Three Forks formation began in mid-2008 and a number of operators are currently drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation and the evolution of completion techniques, we believe that most of our Williston Basin acreage is prospective in the Three Forks formation. We are in the process of completing a well drilled in the Three Forks formation.

Our Middle Bakken development is expected to be comparable to other established operators in the area. For our typical well drilled in the Middle Bakken formation, we expect the initial 30 day production rates to be in the range of 750 Boe/d to 1,100 Boe/d, drilling capital to be in the $8 million to $9 million range and reserve estimates to be from 650 to 850 Mbbls, depending on the area.

Our acreage in the Bakken Shale, as well as a portion of our acreage in the Piceance Basin and Powder River Basin, is leased to us by or with the approval of the federal government or its agencies, and is subject to federal authority, NEPA, the Bureau of Indian Affairs or other regulatory regimes that require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands. These regulatory regimes impose obligations on the federal government and governmental agencies that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals and could result in certain instances in the cancellation of existing leases.

Marcellus Shale

Our Marcellus Shale acreage is located in four principal areas of the play within Pennsylvania: the northeast portion of the play in and near Susquehanna County; the southwest in and around Westmoreland County; centrally in Clearfield and Centre Counties and the east in Columbia County. We have continued to expand our position since our entry into the Marcellus Shale in 2009, both organically and through third-party acquisitions. We are the primary operator on our acreage for all four areas and plan to develop our acreage using horizontal drilling and completion expertise in part gained through operations in our other basins. Our most established area is in Westmoreland County but in the future we expect our most significant drilling area to be in Susquehanna County. A third party gathering system providing the main trunkline out of the area is expected to go into service by the end of October 2011.

For the month of September 2011, we had an average of 16 MMcfe/d of net production from our Marcellus Shale properties. As of December 31, 2010, our properties in the Marcellus Shale included:

- 99,301 total net acres, including 98,387 undeveloped net acres;
- 28 Bcfe of estimated net proved reserves; and

Six net producing wells.

As of September 30, 2011 we were operating four rigs and have an average of five rigs budgeted for 2011. We have allocated approximately $170 million in capital expenditures to drill 62 gross wells on our Marcellus Shale properties in 2011.

The Marcellus Shale formation is the most expansive shale gas play in the United States, spanning six states in the northeastern United States. The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet, covering approximately 95,000 square miles at an average net thickness of 50 feet to 300 feet.

The first commercial well in the Marcellus Shale was drilled and completed in 2005 in Pennsylvania. Since the beginning of 2005, there have been 6,963 wells permitted in Pennsylvania in the Marcellus Shale and 3,030 of the approved wells have been drilled. In 2010, 1,386 wells were drilled in the Marcellus Shale, making it one of the most active and prominent shale gas plays in the United States, and active, widespread drilling in this area is expected to continue. During 2010, there were more than 80 operators active in the play.

Powder River Basin

We own a large position in coal bed methane reserves in the Powder River Basin and together with our co-developer, Lance Oil & Gas Company Inc., control 950,982 acres, of which our ownership represents 425,550 net acres. We share operations with our co-developer and both companies have extensive experience producing from coal formations in the Powder River Basin dating from its earliest commercial growth in the late 1990s. The natural gas produced is gathered by a system owned by our co-developer.

For the month of September 2011, we had an average of 235 MMcfe/d of net production from our Powder River Basin properties. As of December 31, 2010, our properties in the Powder River Basin included:

425,550 total net acres, including 175,371 undeveloped net acres;

348 Bcfe of estimated net proved reserves; and

2,884 net producing wells.

We have allocated approximately $70 million in capital expenditures to drill 411 gross wells on our Powder River Basin properties in 2011. We plan to drill 80 operated wells, participate in 253 wells drilled by our joint venture partner and participate in the drilling of 78 wells drilled by others in 2011.

Our Powder River Basin properties are located in northeastern Wyoming. Our development operations in this basin are focused on coal bed methane plays in the Big George and Wyodak project areas. Initially, coal bed methane wells typically produce water in a process called dewatering. This process lowers pressure, allowing the natural gas to flow to the wellbore. As the coal seam pressure declines, the wells begin producing methane gas at an increasing rate. As the wells mature, the production peaks, stabilizes and then begins declining. The average life of a coal bed methane well in the Powder River Basin ranges from five to 15 years. While these wells generally produce at much lower rates with fewer reserves attributed to them when compared to conventional natural gas wells in the Rocky Mountains, they also typically have higher drilling success rates and lower capital costs.

The coal seams that we target in the Powder River Basin have been extensively mapped as a result of a variety of natural resource development projects that have occurred in the region. Industry data from over 25,000 wellbores drilled through the Ft. Union coal formation allows us to determine critical data such as the aerial extent, thickness, gas saturation, formation pressure and relative permeability of the coal seams we target for development, which we believe significantly reduces our dry hole risk.

San Juan Basin

We acquired our San Juan Basin properties as part of Williams acquisition of Northwest Energy in 1983. These properties represented the first major area of natural gas exploration and development activities for Williams. Our San Juan Basin properties include holdings across the basin producing primarily from the Mesa

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Verde, Fruitland Coal and Mancos shale gas formations. We operate two units in New Mexico (Rosa and Cox Canyon) as well as several non-unit properties, and we operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We also own properties operated by other operators in New Mexico and Colorado. Approximately 60 percent of our net San Juan Basin production comes from our operated properties.

For the month of September 2011, we had an average of 145 MMcfe/d of net production from our San Juan Basin properties. As of December 31, 2010, our properties in the San Juan Basin included:

120,998 total net acres, including 1,576 undeveloped net acres;

554 Bcfe of estimated net proved reserves; and

880 net producing wells.

We have allocated approximately $40 million in capital expenditures to drill 51 gross wells on our San Juan Basin properties in 2011. We plan to drill 16 operated wells in 2011 and participate in the drilling of 35 wells operated by our partners in 2011.

According to a September 2010 Wood Mackenzie report, the San Juan Basin is one of the oldest and most prolific coal bed methane plays in the world. This report states that production from the San Juan Basin in 2010 was expected to average 3.5 Bcfe/d with approximately 60 percent of net gas production derived from the Fruitland coal bed. The Fruitland coal bed extends to depths of approximately 4,200 ft with net thickness ranging from zero to 100 feet. The Mesa Verde play is the top producing tight gas play in the basin with total thickness ranging from 500 to 2,500 feet. The Mesa Verde is underlain by the upper Mancos Shale and overlain by the Lewis Shale.

Apco

We hold an approximate 69 percent controlling equity interest in Apco. Apco in turn owns interests in several blocks in Argentina, including concessions in the Neuquén, Austral, Northwest and San Jorge Basins, and in 3 exploration permits in Colombia, with its primary properties consisting of the Neuquén and Austral Basin concessions. Apco s oil and gas reserves are approximately 57 percent oil, 39 percent natural gas and four percent liquefied petroleum gas. For the month of September 2011, Apco had an average of 12.9 Mboe/d of net production. As of December 31, 2010, Apco s properties included:

586,288 total net acres, including 556,661 undeveloped net acres;

45.9 MMboe of estimated net proved reserves; and

322 net producing wells.

Apco intends to participate in the drilling of 37 wells operated by its partners in 2011 of which Apco has allocated, for its direct ownership interest, approximately $30 million in capital expenditures.

The government of Argentina has implemented price control mechanisms over the sale of natural gas and over gasoline prices in the country. As a result of these controls and other actions by the Argentine government, sales price realizations for natural gas and oil sold in Argentina are generally below international market levels and are significantly influenced by Argentine governmental actions.

Neuquén Basin. Apco participates in a joint venture partnership with Petrolera and Petrobras Argentina S.A. for the exploration and development of the Entre Lomas oil and gas concession in the provinces of Río Negro and Neuquén in southwest Argentina. In 2007, the partners created two new joint ventures consisting of the same partners with the same interests in order to expand operations into two areas adjacent to Entre Lomas, the Agua Amarga exploration permit in the province of Río Negro, and the Bajada del Palo concession in the province of Neuquén. In 2009, a portion of the Agua Amarga permit was converted to a 25-year exploitation concession called Charco del Palenque.

The Entre Lomas concession covers a surface area of approximately 183,000 acres and produces oil and gas from seven fields, the largest of which is Charco Bayo/Piedras Blancas. The Entre Lomas concession has a primary term of 25 years that expires in the year 2016 with an option to extend for an additional ten-year period based on terms to be agreed with the government. The Bajada del Palo concession has a total surface area of approximately 111,000 acres. In 2009, the Bajada del Palo concession term was extended to September 2025.

The Agua Amarga exploration area was awarded to Petrolera by the province of Río Negro in 2007. The property has a total surface area of approximately 95,000 acres and is located immediately to the southeast of the Entre Lomas concession. The first exploration period was scheduled to end in May 2010 and was extended for one year until May 2011. The completion of Apco s work commitments and additional activities executed in the area has enabled Apco to request an additional one-year extension. If granted, the first exploration period would end on May 2012. In 2009, a portion of the Agua Amarga area covering approximately 18,000 acres was converted to an exploitation concession called Charco del Palenque with a 25-year term and a five-year optional extension period.

Austral Basin Properties. Apco holds a 25.78 percent non-operated interest in a joint venture engaged in exploration and production activities in three concessions located on the island of Tierra del Fuego, which we refer to as the TDF concessions. The operator of the TDF concessions is ROCH S.A., a privately owned Argentine oil and gas company. The TDF concessions cover a total surface area of approximately 467,000 gross acres, or 120,000 acres net to Apco. Each of the concessions extends three kilometers offshore with their eastern boundaries paralleling the coastline. The most developed of the three concessions is the Las Violetas concession which is the largest onshore concession on the Argentine side of the island of Tierra del Fuego. The concessions have terms of 25 years that expire in 2016 with an option to extend the concessions for an additional ten-year period based on terms to be agreed with the government.

Northwest Basin Properties. Apco holds a 1.5 percent non-operated interest in the Acambuco concession located in the province of Salta in northwest Argentina on the border with Bolivia. The concession covers an area of 294,000 acres, and is one of the largest gas producing concessions in Argentina. Wells drilled to the Huamampampa formation in the Acambuco concession have generally required one year to drill with total costs for drilling and completion ranging from $50 to $70 million.

San Jorge Basin Properties. In the San Jorge Basin, Apco s areas are more prospective and exploratory in nature. In the Sur Río Deseado Este concession in the province of Santa Cruz, Apco has a 16.94 percent working interest in an exploitation area with limited oil production and an 88 percent working interest in an exploratory area in the northern sector of the concession. Apco sold its interest in the Cañadón Ramirez concession at the end of 2010.

Other Properties

Our other holdings are comprised of assets in the Barnett Shale located in north central Texas, gas reserves in the Green River Basin of southwest Wyoming, interests in the Arkoma Basin in southeastern Oklahoma and additional international assets in northwest Argentina that are not part of Apco s holdings.

For the month of September 2011, we had an average of 82 MMcfe/d of net production from continuing operations from our other properties. As of December 31, 2010, our other properties included:

- 327,390 total net acres, including 245,497 undeveloped net acres;
- 290 Bcfe of estimated net proved reserves; and
- 532 net producing wells.

As of September 30, 2011 we were operating one rig on our other properties. We have allocated approximately $85 million in capital expenditures to drill 94 gross wells on our other properties in 2011.

Our Barnett Shale properties produce predominately natural gas from horizontal wells, where we are the primary operator and have drilled more than 200 wells. Our Arkoma Basin properties include 441 gross wells producing gas from coal and shale formations. We have initiated a process to seek offers to sell our Arkoma Basin properties, which include approximately 104,000 net acres, including approximately 48,000 undeveloped net acres. Such properties were classified as held for sale and reported as discontinued operations as of June 30, 2011, comprised less than one percent of our assets and are not included in our average daily net production amount for the month of June 2011.

Reserves and Production Information

We have significant oil and gas producing activities primarily in the Rocky Mountain, northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. Proved reserves and revenues related to international activities are approximately five percent and three percent, respectively, of our total international and domestic proved reserves and revenues from producing activities. Accordingly, unless specifically stated otherwise, the information in the remainder of this Business section relates only to the oil and gas activities in the United States.

Oil and Gas Reserves

The following table outlines our estimated net proved reserves expressed on a gas equivalent basis for the reporting periods December 31, 2010, 2009 and 2008. We prepare our own reserves estimates and the majority of our reserves are audited by NSAI and M&L. Proved reserves information is reported as gas equivalents, since oil volumes are insignificant in the three years shown below. Reserves for 2010 are approximately 97 percent natural gas. Reserves are more than 99 percent natural gas for 2009 and 2008. Oil reserves increased to approximately three percent of total proved reserves in 2010 as a result of a fourth quarter acquisition of properties in the Bakken Shale.

Summary of oil and gas reserves:

	December 31,		
	2010	2009	2008
		(Bcfe)(1)	
Proved developed reserves	2,498	2,387	2,456
Proved undeveloped reserves	1,774	1,868	1,883
Total proved reserves	4,272	4,255	4,339

(1) Gas equivalents are calculated using a ratio of six thousand cubic feet of natural gas to one barrel of oil.

Basin / Shale	Estimated Net Proved Reserves December 31, 2010 (Bcfe)
Piceance Basin	2,927
Bakken Shale	136
Marcellus Shale	28
Powder River Basin	348
San Juan Basin	554

Other(1)	279
Total(2)	4,272

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties.

(2) Of our total 4,272 Bcfe of net proved reserves as of December 31, 2010, three percent are oil.

We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than with the U.S. Department of Energy and the SEC. The estimates furnished to the Department of Energy have been consistent with those furnished to the SEC.

Our 2010 year-end estimated proved reserves were derived using an average price of $4.31 per Mcf, which is the 12-month average, first-of-the-month price for the applicable indices for each basin as adjusted for locational price differentials. During 2010, we added 508 Bcfe of net additions to our proved reserves through drilling 1,162 gross wells at a capital cost of approximately $988 million.

Reserves estimation process

Our reserves are estimated by deterministic methods using an appropriate combination of production performance analysis and volumetric techniques. The proved reserves for economic undrilled locations are estimated by analogy or volumetrically from offset developed locations. Reservoir continuity and lateral persistence of our tight-sands, shale and coal bed methane reservoirs is established by combinations of subsurface analysis and analysis of 2D and 3D seismic data and pressure data. Understanding reservoir quality may be augmented by core samples analysis.

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate by providing supporting information such as pricing, capital costs, expenses, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our reserves analysis department. The reserves analysis department s responsibilities also include performing an internal review of reserves data for reasonableness and accuracy, working with the third-party consultants and the asset teams to successfully complete the third-party reserves audit, finalizing the year-end reserves report and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. Early in the year, we begin with a review of the existing internal processes and controls to identify where improvements can be made from the prior year s reporting cycle. Later in the year, the reserves staffs from the asset teams submit their preliminary reserves data to the reserves analysis department. After review by the reserves analysis department, the data is submitted to our third party engineering consultants, NSAI and M&L, to begin their audits. After this point, reserves data analysis and further review are conducted and iterated between the asset teams, reserves analysis department and our third party engineering consultants. In early December, reserves are reviewed with senior management. The process concludes when all parties agree upon the reserve estimates and audit tolerance is achieved.

The reserves estimates resulting from our process are subjected to both internal and external controls to promote transparency and accuracy of the year-end reserves estimates. Our internal reserves analysis team is independent and does not work within an asset team or report directly to anyone on an asset team. The reserves analysis department provides detailed independent review and extensive documentation of the year-end process. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated. The compensation of our reserves analysis team is not linked to reserves additions or revisions.

Approximately 93 percent of our total year-end 2010 domestic proved reserves estimates were audited by NSAI. When compared on a well-by-well basis, some of our estimates are greater and some are less than the NSAI estimates. NSAI is satisfied with our methods and procedures in preparing the December 31, 2010 reserves estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us.

In addition, reserves estimates related to properties associated with the former Williams Coal Seam Gas Royalty Trust were audited by M&L. These properties represent approximately one percent of our total domestic proved reserves estimates. The Williams Coal Seam Gas Royalty Trust terminated effective March 1, 2010 and we purchased all the remaining properties from the trust in October 2010.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserves audit is the Director of Reserves and Production Services. The Director s qualifications include 28 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in Physical Sciences from the University of Houston and membership in the American Association of Petroleum Geologists and The Society of Petroleum Engineers.

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Proved undeveloped reserves

The majority of our reserves is concentrated in unconventional tight-sands, shale and coal bed gas reservoirs. We use available geoscience and engineering data to establish drainage areas and reservoir continuity beyond one direct offset from a producing well, which provides additional proved undeveloped reserves. Inherent in the methodology is a requirement for significant well density of economically producing wells to establish reasonable certainty. In fields where producing wells are less concentrated, only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification. No new technologies were used to assign proved undeveloped reserves.

At December 31, 2010, our proved undeveloped reserves were 1,774 Bcfe, a decrease of 94 Bcfe over our December 31, 2009 proved undeveloped reserves estimate of 1,868 Bcfe. During 2010, 280 Bcfe of our December 31, 2009 proved undeveloped reserves were converted to proved developed reserves at a cost of $633 million. An additional 129 Bcfe was added due to the development of unproved locations. As of 2010 year-end, we have reclassified a net 253 Bcfe from proved to probable reserves attributable to locations not expected to be developed within five years. These reclassified reserves are predominately in the Piceance Basin where we have a large inventory of drilling locations and have been offset by the addition of 342 Bcfe of new proved undeveloped drilling locations.

All proved undeveloped locations are scheduled to be spud within the next five years. Based on current projections, we expect to add additional rigs in 2013 in the Piceance Basin. Our undeveloped estimate contains 91 Bcfe of aging proved undeveloped reserves, or those reserves which are approaching the five-year limit before being reclassified to probable reserves. The majority of these are scheduled to be spud by year-end 2011.

Oil and Gas Properties and Production, Production Prices and Production Costs

The following table summarizes our net production for the years indicated.

	Year Ended December 31,		
	2010	**2009**	**2008**
Production Data:			
Natural Gas (MMcf)			
U.S.			
Piceance Basin	241,371	252,387	240,285
Other(1)	162,571	171,691	156,497
Argentina(2)	7,304	7,728	6,392
Total	411,246	431,806	403,174
Oil (MBbls)			
U.S.	857	803	731
Argentina(2)	2,035	1,998	1,991
Total	2,892	2,801	2,722
Combined Equivalent Volumes (MMcfe)(2)	428,598	448,612	419,506
Combined Equivalent Volumes (MBoe)	71,433	74,769	69,918
Average Daily Combined Equivalent Volumes (MMcfe/d)			
U.S.			
Piceance Basin	674	703	666
Other(1)	447	472	430

Argentina(2)	53	54	50
Total	1,174	1,229	1,146

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(1) Excludes production from our Arkoma Basin operations which were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our total production.

(2) Includes approximately 69 percent of Apco s production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

The following tables summarize our domestic sales price and cost information for the years indicated.

	Year Ended December 31,		
	2010	2009	2008
Realized average price per unit(1):			
Natural gas, without hedges (per Mcf)(2)	$ 4.33	$ 3.39	$ 6.84
Impact of hedges (per Mcf)(2)	0.82	1.45	0.09
Natural gas, with hedges (per Mcf)(2)	$ 5.15	$ 4.84	$ 6.93
Oil, without hedges (per Bbl)	$ 66.32	$ 47.39	$ 84.63
Impact of hedges (per Bbl)			
Oil, with hedges (per Bbl)	$ 66.32	$ 47.39	$ 84.63
Price per Boe, without hedges(3)	$ 26.44	$ 20.63	$ 41.52
Price per Boe, with hedges(3)	$ 31.32	$ 29.23	$ 42.03
Price per Mcfe, without hedges(3)	$ 4.41	$ 3.44	$ 6.92
Price per Mcfe, with hedges(3)	$ 5.22	$ 4.87	$ 7.00

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our total revenues.

(2) Includes NGLs.

(3) Realized average prices reflect realized market prices, net of fuel and shrink.

	Year Ended December 31,		
	2010	2009	2008
Expenses per Mcfe(1):			
Operating expenses:			
Lifting costs and workovers	$ 0.46	$ 0.39	$ 0.45
Facilities operating expense	0.14	0.14	0.15

Other operating and maintenance	0.05	0.05	0.04
Total LOE	$ 0.65	$ 0.58	$ 0.64
Gathering, processing and transportation charges	0.80	0.64	0.57
Taxes other than income	0.27	0.19	0.60
Production cost	$ 1.72	$ 1.41	$ 1.81
General and administrative	$ 0.60	$ 0.56	$ 0.60
Depreciation, depletion and amortization	$ 2.10	$ 2.03	$ 1.80

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations as of June 30, 2011.

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Productive Oil and Gas Wells

The table below summarizes 2010 productive wells by area.*

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance Basin	3,923	3,587		
Bakken Shale			19	13
Marcellus Shale	14	6		
Powder River Basin	6,404	2,884		
San Juan Basin	3,267	881		
Other(1)	1,626	532		
Total	15,234	7,890	19	13

* We use the term gross to refer to all wells or acreage in which we have at least a partial working interest and net to refer to our ownership represented by that working interest.

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties. Our Arkoma Basin operations were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our assets.

At December 31, 2010, there were 181 gross and 105 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2010.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance Basin	133,428	102,835	157,017	108,165	290,445	211,000
Bakken Shale	16,178	13,483	114,245	75,937	130,423	89,420
Marcellus Shale	1,828	914	108,023	98,387	109,851	99,301
Powder River Basin	551,113	250,179	399,869	175,371	950,982	425,550
San Juan Basin	237,587	119,422	2,100	1,576	239,687	120,998
Other(1)	149,414	81,731	326,778	241,254	476,191	322,986
Total	1,089,548	568,565	1,108,032	700,690	2,197,580	1,269,255

(1) Other includes Barnett Shale, Arkoma and Green River Basins, other Williston Basin acreage and miscellaneous smaller properties. Our Arkoma Basin operations were classified as held for sale and reported as discontinued operations as of June 30, 2011 and comprised less than one percent of our assets.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2010, 2009 and 2008.

The following table summarizes domestic drilling activity by number and type of well for the periods indicated.

	2010		2009		2008	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance Basin	398	360	349	303	687	624
Bakken Shale	0	0	n/a	n/a	n/a	n/a
Marcellus Shale	8	3	8	4	n/a	n/a
Powder River Basin	531	242	233	95	702	324
San Juan Basin	43	15	77	39	95	37
Other	177	38	208	45	298	65
Productive, development	1,157	658	875	486	1,782	1,050
Productive, exploration	0	0	3	1	4	2
Total Productive	1,157	658	878	487	1,786	1,052
Dry, development	5	3	2	0	1	0
Dry, exploration	0	0	2	1	0	0
Total Drilled	1,162	661	882	488	1,787	1,052

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties.

In 2010, we drilled five gross nonproductive development wells and three net nonproductive development wells. Total gross operated wells drilled were 656 in 2010, 472 in 2009 and 1,125 in 2008.

Present Activities

At September 30, 2011, we had 41 gross (22 net) wells in the process of being drilled.

Scheduled Lease Expirations

Domestic. The table below sets forth, as of September 30, 2011, the gross and net acres scheduled to expire over the next several years. The acreage will not expire if we are able to establish production by drilling wells on the lease prior to the expiration date. We expect to hold substantially all of the Bakken and Marcellus Shale acreage by drilling prior to its expiration. Approximately 80% of the acreage shown in the table below as Other in 2011 through 2013 consists of our Arkoma Basin operations which are currently held for sale.

	2011	2012	2013	2014 +	Total
Piceance Basin	1,681	5,529	2,878	3,766	13,854
Bakken Shale	280	13,975	51,143	7,709	73,107
Marcellus Shale	331	2,273	38,682	56,591	97,877
Powder River Basin	826	9,556	15,232	1,147	26,761
San Juan Basin					
Other	18,586	11,949	9,351	89,626	129,512
Total (Gross Acres)	21,704	43,282	117,286	158,839	341,111

	2011	2012	2013	2014 +	Total
Piceance Basin	1,148	2,156	2,182	3,207	8,693
Bakken Shale	189	13,362	49,654	2,577	65,782
Marcellus Shale	273	1,756	30,149	47,338	79,516
Powder River Basin	466	3,239	7,399	599	11,703
San Juan Basin					
Other	13,879	9,743	8,169	90,589	122,380
Total (Net Acres)	15,955	30,256	97,553	144,310	288,074

International. In general, all of our concessions have expiration dates of either 2025 or 2026, except for two concessions that expire beyond 2030 and four that expire in 2015 and 2016. With respect to these four we are negotiating ten year extensions for which we have contractual rights. These four concessions represent approximately 169,000 acres net to Apco or approximately 116,000 acres net to WPX based on our 69% ownership in Apco. Our remaining properties in Argentina and Colombia are all exploration permits or exploration contracts that have much shorter terms and on which we have made exploration investment commitments that must be completed. These areas will expire in 2011 to 2013 unless discoveries are made. There are opportunities to extend exploration terms for a year with good technical justification. We can either declare the portions of these blocks where we have made discoveries commercial and convert that acreage to a concession or exploitation acreage with a specified term for production of 25 to 35 years, or relinquish a portion or the balance of the acreage if we are not willing to make further exploration commitments.

Gas Management

Our sales and marketing activities to date include the sale of our natural gas and oil production, in addition to third party purchases and subsequent sales to Williams Partners for fuel and shrink gas. Following the completion of the spin-off of our stock to Williams   stockholders, we do not expect to continue to provide fuel and shrink gas services to Williams Partners   midstream business on a long-term basis. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related hedges. We also sell natural gas purchased from working interest owners in operated wells and other area third party producers. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in oil and gas revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Delivery Commitments

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. The Piceance, being our largest producing basin, generates ample production to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of natural gas is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure. This obligation expires in 2014.

Purchase Commitments

In connection with a gathering agreement entered into by Williams Partners with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu/d of natural gas at Transco Station 515 (Marcellus Shale) priced at market prices from the same third party. Purchases under the 12-year contract are expected to begin in the third quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Hedging Activity

To manage the commodity price risk and volatility of owning producing natural gas properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Customers

Oil and gas production is sold through our sales and marketing activities to a variety of purchasers under various length contracts ranging from one day to multi-year at market based prices. Our third party customers include other producers, utility companies, power generators, banks, marketing and trading companies and midstream service providers. In 2010, natural gas sales to BP Energy Company accounted for approximately 13 percent of our revenues. We believe that the loss of one or more of our current natural gas, oil or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. In addition, leases on Native American reservations are subject to Bureau of Indian Affairs and other approvals unique to those locations. As is customary in the industry in the case of undeveloped properties, a limited investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which can result in litigation and delay or loss of our ability to realize the benefits of our leases.

Seasonality

Generally, the demand for natural gas decreases during the spring and fall months and increases during the winter months and in some areas during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Conversely, during extreme weather events such as blizzards, hurricanes, or heat waves, pipeline systems can become temporary constraints to supply meeting demand thus amplifying localized price spikes. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the warmer months. This can lessen seasonal demand fluctuations. World weather and resultant prices for liquefied natural gas can also affect deliveries of competing liquefied natural gas into this country from abroad, affecting the price of domestically produced natural gas. In addition, adverse weather conditions can also affect our production rates or otherwise disrupt our operations.

Competition

We compete with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

In our gas management services business, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

Environmental Matters and Regulation

Our operations are subject to numerous federal, state, local, Native American tribal and foreign laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental

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protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Clean Water Act (CWA) and the Clean Air Act (CAA). These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, in March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes the addition of Energy Extraction Activities to its enforcement priorities list. According to the EPA s website, some energy extraction activities, such as new techniques for oil and gas extraction and coal mining, pose a risk of pollution of air, surface waters and ground waters if not properly controlled. To address these concerns, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements. This initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

Hazardous Substances and Wastes. CERCLA, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act (RCRA) generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. An environmental organization recently petitioned the EPA to reconsider certain RCRA exemptions for exploration and production wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the CWA, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges. The CWA and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. In 2007, 2008 and 2010, we received three separate information requests from the EPA pursuant to Section 308 of the CWA. The information requests required us to provide the EPA with information about releases at three of our facilities and our compliance with spill prevention, control and countermeasure requirements. We have responded to these information requests and no proceeding or enforcement actions have been initiated. We believe that our operations are in substantial compliance with the CWA.

On April 25, 2011, the EPA issued for public comment a new draft general permit for stormwater discharges from construction activities involving more than one acre. The EPA is developing this draft construction general permit (CGP) to implement the new Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. Because the existing permit is set to expire on June 30, 2011, the EPA also is proposing to extend that permit until January 31, 2012. When EPA finalizes the new CGP, likely in early January 2012, operators of construction activities will be subject to significantly more stringent erosion and sediment control, inspection, and monitoring requirements.

Air Emissions. The CAA and associated state laws and regulations restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases (GHGs) have been developed by the EPA and may increase the costs of compliance for some facilities.

Oil Pollution Act. The Oil Pollution Act of 1990, as amended (OPA) and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act. The Endangered Species Act (ESA) restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety. The Occupational Safety and Health Act (OSHA) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Safe Drinking Water Act. The Safe Drinking Water Act (SDWA) and comparable state statutes restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state s environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. We use hydraulic fracturing as a means to maximize the productivity of our oil and gas wells in all of the domestic basins in which we operate other than the Arkoma and Powder River Basins. Our net acreage position in the basins in which hydraulic fracturing is utilized total approximately 550,000 acres and represents approximately 94% of our domestic proved undeveloped oil and gas reserves. Although average drilling and completion costs for each basin will vary, as will the cost of each well within a given basin, on average approximately 31% of the drilling and completion costs for each of our wells for which we use hydraulic fracturing is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget.

The protection of groundwater quality is extremely important to us. We follow applicable standard industry practices and legal requirements for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), which conduct many inspections during operations that include hydraulic fracturing. Industry standards and legal requirements for groundwater protection focus on five principal areas: (i) pressure testing of well construction and integrity, (ii) lining of pits used to hold water and other fluids used in the drilling process isolated from surface water and groundwater, (iii) casing and cementing practices for wells to ensure separation of the production zone from groundwater, (iv) disclosure of the chemical content of fracturing

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liquids, and (v) setback requirements as to the location of waste disposal areas. The legal requirements relating to the protection of surface water and groundwater vary from state to state and there are also federal regulations and guidance that apply to all domestic drilling. In addition, the American Petroleum Institute publishes industry standards and guidance for hydraulic fracturing and the protection of surface water and groundwater. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing.

In addition to the required use of and specifications for casing and cement in well construction, there are additional regulatory requirements and best practices that we follow to ensure wellbore integrity and full isolation of any underground aquifers and protection of surface waters. These include the following:

Prior to perforating the production casing and hydraulic fracturing operations, the casing is pressure tested.

Before the fracturing operation commences, all surface equipment is pressure tested, which includes the wellhead and all pressurized lines and connections leading from the pumping equipment to the wellhead. During the pumping phases of the hydraulic fracturing treatment, specialized equipment is utilized to monitor and record surface pressures, pumping rates, volumes and chemical concentrations to ensure the treatment is proceeding as designed and the wellbore integrity is sound. Should any problem be detected during the hydraulic fracturing treatment, the operation is shut down until the problem is evaluated, reported and remediated.

As a means to protect against the negative impacts of any potential surface release of fluids associated with the hydraulic fracturing operation, special precautions are taken to ensure proper containment and storage of fluids. For example, any earthen pits containing non-fresh water must be lined with a synthetic impervious liner. These pits are tested regularly, and in certain sensitive areas have additional leak detection systems in place. At least two feet of freeboard, or available capacity, must be present in the pit at all times. In addition, earthen berms are constructed around any storage tanks, any fluid handling equipment, and in some cases around the perimeter of the location to contain any fluid releases. These berms are considered to be a secondary form of containment and serve as an added measure for the protection of groundwater.

We conduct baseline water monitoring in many of the basins in which we use hydraulic fracturing:

In Colorado, baseline water monitoring may be required by the Colorado Oil and Gas Conservation Commission (COGCC) or BLM as a condition of approval for the drilling permit, but otherwise it is not a requirement. The industry is currently working with the COGCC in preparing a voluntary baseline water monitoring program by basin. The Company has committed to this program that will likely go into effect later in 2011.

In the Barnett Shale, and with landowner approval, we perform water monitoring of fresh water wells within an agreed upon distance on a voluntary basis, even though not required by state regulation.

In Pennsylvania, we perform baseline water monitoring pursuant to Pennsylvania Department of Environmental Protection requirements.

There are currently no regulatory requirements to conduct baseline water monitoring in the Bakken Shale or the San Juan Basin. We plan to begin voluntarily conducting water monitoring in the Bakken Shale. The majority of our assets in the San Juan Basin are on federal lands, and there are few cases where water wells are within one to two miles of our wells, which is outside the range that we would typically sample.

Once a pipe is set in place, cement is pumped into the well where it hardens and creates a permanent, isolating barrier between the steel casing pipe and surrounding geological formations. This aspect of the well design essentially eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. Furthermore, in the basins in which we conduct hydraulic fracturing, the hydrocarbon bearing formations are separated from any usable underground aquifers by thousands of feet of impermeable

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rock layers. This wide separation serves as a protective barrier, preventing any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones.

In addition, the vendors we employ to conduct hydraulic fracturing are required to monitor all pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis and data is recorded to ensure protection of groundwater.

The cement and steel casing used in well construction can have rare failures. Any failure in isolation is reported to the applicable oil and gas regulatory body. A remediation procedure is written and approved and then completed on the well before any further operations or production is commenced. Possible isolation failures may result from:

Improper cementing work. This can create conditions in which hydraulic fracturing fluids and other natural occurring substances can migrate into the surrounding geological formation. Production casing cementing tops and cement bond effectiveness are evaluated using either a temperature log or an acoustical cement bond log prior to any completion operations. If the cement bond or cement top is determined to be inadequate for zone isolation, remedial cementing operations are performed to fill any voids and re-establish integrity. As part of this remedial operation, the casing is again pressure tested before fracturing operations are initiated.

Initial casing integrity failure. The casing is pressure tested prior to commencing completion operations. If the test fails due to a compromise in the casing, the applicable oil and gas regulatory body will be notified and a remediation procedure will be written, approved, and completed before any further operations are conducted. In addition, casing pressures are monitored throughout the fracturing treatment and any indication of failure will result in an immediate shutdown of the operation.

Well failure or casing integrity failure during production. Loss of wellbore integrity can occur over time even if the well was correctly constructed due to downhole operating environments causing corrosion and stress. During production, the bradenhead, casing, and tubing pressures are monitored and a casing failure can be identified and evaluated. Remediation could include placing additional cement behind casing, installing a casing patch, or plugging and abandoning the well, if necessary.

Fluid leakoff during the fracturing process. Fluid leakoff can occur during hydraulic fracturing operations whereby some of the hydraulic fracturing fluid flows through the artificially created fractures into the micropore or pore spaces within the formation, existing natural factures in the formation, or small fractures opened into the formation by the pressure in the induced fracture. Fluid leakoff is accounted for in the volume design of nearly every fracturing job and pump-in tests are often conducted prior to fracturing jobs to estimate the extent of fluid leakoff. In certain situations, a very fine grain sand is added in the initial part of the treatment to seal-off any small fractures of micropore spaces and mitigate fluid leak-off.

Approximately 99% of hydraulic fracturing fluids are made up of water and sand. We utilize major hydraulic fracturing service companies whose research departments conduct ongoing development of greener chemicals that are used in fracturing. We evaluate, test, and where appropriate adopt those products that are more environmentally friendly. We have also chosen to participate in a voluntary fracturing chemical registry that is a public website: www.fracfocus.org at which interested persons can find out information about fracturing fluids. This registry is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission and provides our industry with an avenue to voluntarily disclose chemicals used in the hydraulic fracturing process. The Company registered with the FracFocus Chemical Disclosure Registry in April 2011 and began uploading data when the registry went live on April 11, 2011. To date, we have loaded data on 59 wells. We plan to add all wells fractured since January 1, 2011 to the site. Consistent with other industry participants, we are not planning to add data on wells drilled prior to 2011. The information included on this website is not incorporated by reference in this prospectus.

We currently recycle over 90% of the water recovered from our operations in the Piceance Basin and the Marcellus Shale. This recycling greatly lessens the demand on local natural water resources. We recycled more than 30,000 barrels of water per day on average in 2010. Across all areas where we conduct hydraulic

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fracturing operations, approximately 9.6 million barrels of water (53,000 barrels of water per day) were used during the first six months of 2011 in our hydraulic fracturing activities. We recover approximately 80% of this volume during the first one to two months of flowback and production with small additional volumes recovered over longer time frames. Any water from our hydraulic fracturing operations that is not recycled is disposed of in a way that does not impact surface waters.

Despite our efforts to minimize impacts on the environment from hydraulic fracturing activities, in light of the volume of our hydraulic fracturing activities, we have occasionally been engaged in litigation and received requests for information, notices of alleged violation, and citations related to the activities of our hydraulic fracturing vendors, none of which has resulted in any material costs or penalties.

Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate are considering Fracturing Responsibility and Awareness of Chemicals Act (FRAC Act) bills and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, the EPA s interpretation without formal rule making has been challenged and industry groups have filed suit challenging the EPA s interpretation. If the EPA prevails in this lawsuit, its interpretation could result in enforcement actions against service providers or companies that used diesel products in the hydraulic fracturing process or could require such providers or companies to conduct additional studies regarding diesel in the groundwater. Furthermore, the State of Colorado, in response to an EPA request, has asked companies operating in Colorado, including us, to report whether diesel products were used in the hydraulic fracturing process from 2004 to 2009. In response to this inquiry we consulted our service providers and reported to the State of Colorado that at least nine wells were subject to hydraulic fracturing utilizing fluids that contained chemical products that contained diesel fuel as a component. The State of Colorado may conduct additional investigations related to this inquiry. Any enforcement actions or requirements of additional studies or investigations by the EPA or the State of Colorado could increase our operating costs and cause delays or interruptions of our operations.

On October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The results of this study, expected in late 2012, could result in additional regulations, which could lead to operational burdens similar to those described above. In connection with the EPA study, we have received a request for information from the EPA for 52 of our wells located in various basins that have been hydraulically fractured. The requested information covers well design, construction and completion practices, among other things. We understand that similar requests were sent to eight other companies that own or operate wells that utilized hydraulic fracturing.

In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011. The report concludes that the risk of fracturing fluids contaminating drinking water sources through fractures in the shale formations is remote. It also states that development of the nation s shale resources has produced major economic benefits. The report includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The Government

Accountability Office is also examining the environmental impacts of produced water and the Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. The United States Department of the Interior is also considering whether to impose disclosure requirements or other mandates for hydraulic fracturing on federal land.

Several states, including Pennsylvania, Texas, Colorado, North Dakota and New Mexico, have adopted or are considering adopting, regulations that could restrict or impose additional requirements related to hydraulic fracturing. For example, on June 17, 2011, Texas signed into law a mandate for public disclosure of the chemicals that operators use during hydraulic fracturing in Texas. The law goes into effect September 1, 2011. Implementing rules were proposed on September 9, 2011 and state regulators have until 2013 to complete the rulemaking process. Pennsylvania also requires that detailed information be disclosed regarding the hydraulic fracturing fluids, including but not limited to, a list of chemical additives, volume of each chemical added, and list of chemicals in the material safety data sheets. Since June 2009, Colorado has required all operators to maintain a chemical inventory by well site for each chemical product used downhole or stored for use downhole during drilling, completion and workover operations, including fracture stimulation in an amount exceeding 500 pounds during any quarterly reporting period. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

In addition, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities, while some state and local governments in the Marcellus Shale have considered or imposed temporary moratoria on drilling operations using hydraulic fracturing until further study of the potential environmental and human health impacts by the EPA or the relative state agencies are completed. Additionally, publicly operated treatment works facilities in Pennsylvania have ceased taking wastewater from hydraulic fracturing operations, and we are now recycling this wastewater and utilizing it in subsequent hydraulic fracturing operations. At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

Global Warming and Climate Change. Recent scientific studies have suggested that emissions of GHGs, including carbon dioxide and methane, may be contributing to warming of the earth s atmosphere. Both houses of Congress have previously considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The EPA has begun to regulate GHG emissions. On December 15, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public heath and the environment. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted two sets of regulations under the CAA. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Most recently, on November 30, 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage, and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. We are required to report our GHG emissions under this rule but are not subject to GHG permitting requirements. Several of the EPA s GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact our operations. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase our litigation risk for such claims. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Foreign Operations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries. For example, the Argentine Department of Energy and the government of the provinces in which Apco s oil and gas producing concessions are located have environmental control policies and regulations that must be adhered to when conducting oil and gas exploration and exploitation activities. Future environmental regulation of certain aspects of our operations in Argentina and Columbia that are currently unregulated and changes in the laws or regulations could materially affect our financial condition and results of operations.

Other Regulation of the Oil and Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, local and foreign authorities, including Native American tribes in the United States. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and NGLs are not currently regulated and are made at market prices.

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Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities including seasonal wildlife closures;
- the employment of tribal members or use of tribal owned service businesses;
- the rates of production or allowables;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, oil and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from our wells, negatively affect the economics of production from these wells, or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where we operate. The New Mexico Oil Conservation requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Corps and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the Corps does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. The FERC s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under the FERC s current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Operation on Native American Reservations

A portion of our leases are, and some of our future leases may be, regulated by Native American tribes. In addition to regulation by various federal, state, local and foreign agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and BLM, and the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native

American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements, or delays in obtaining necessary approvals or permits pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Employees

At September 30, 2011, Williams had 1,073 full-time employees dedicated to our business. This number does not include employees of Williams who provide services to our business and other of Williams businesses. We have no employees as of the date hereof, nor will we at the completion of this offering. Rather, effective as of January 1, 2012, Williams will transfer to us the employees who provide services to our business.

Offices

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172.

Legal Proceedings

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties, and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class members for class certification, reserved two claims for court resolution, resolved all other class claims relating to past calculation of royalty and overriding royalty payments, and established certain rules to govern future royalty and overriding royalty payments. This settlement resolved all claims relating to past withholding for ad valorem tax payments and established a procedure for refunds of any such excess withholding in the future. The first reserved claim is whether we are entitled to deduct in our calculation of royalty payments a portion of the costs we incur beyond the tailgates of the treating or processing plants for mainline pipeline transportation. We received a favorable ruling on our motion for summary judgment on the first reserved claim. Plaintiffs appealed that ruling and the Colorado Court of Appeals found in our favor in April 2011. In June 2011, Plaintiffs filed a Petition for Certiorari with the Colorado Supreme Court. We anticipate that the Court will issue a decision on whether to grant further review later in 2011 or early in 2012. The second reserved claim relates to whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are thus entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate trial on the second reserved claim following resolution of the first reserved claim. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims. However, it is reasonably possible that the ultimate resolution of this item could result in a future charge that may be material to our results of operations.

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including

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various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Pursuant to the separation and distribution agreement, Williams will indemnify us for any cash amounts determined to be owed by us, and will be entitled to any cash amounts received by us, in connection with pending proceedings related to these matters.

Reporting of natural gas-related information to trade publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. On January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. We expect that the Colorado plaintiffs will appeal now that the court s order became final on July 18, 2011.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. On July 22, 2011, the plaintiffs filed their notice of appeal with the Nevada district court. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

Pursuant to the separation and distribution agreement, Williams will indemnify us for any cash payments (including indirect, punitive or consequential damages) incurred by us in connection with pending proceedings related to these matters.

EPA Settlement

On August 26, 2011, we signed an Administrative Complaint and Consent Agreement with EPA Region 8 to settle allegations of noncompliance with the Clean Air Act Prevention of Significant Deterioration provisions with respect to the absence of emission permits at 76 locations in the Fort Berthold Indian Reservation in North Dakota. We agreed to pay $228,000 in penalties in connection with this settlement.

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MANAGEMENT

Directors and Executive Officers

Set forth below is certain information regarding persons who serve as our executive officers and directors or who will become executive officers and directors.

Name	Age	Position
Alan S. Armstrong	49	Chairman of the Board(1)
Ralph A. Hill	52	Chief Executive Officer and Prospective Director
Donald R. Chappel	60	Chief Financial Officer and Prospective Director(1)(2)
Ted T. Timmermans	54	Chief Accounting Officer(3)
James J. Bender	54	General Counsel and Corporate Secretary(4)
Robyn L. Ewing	56	Chief Administrative Officer(3)
Rodney J. Sailor	52	Treasurer and Deputy Chief Financial Officer(5)
George A. Lorch	69	Prospective Director
William G. Lowrie	67	Prospective Director(6)
Bryan K. Guderian	52	Senior Vice President of Operations(7)
Neal A. Buck	55	Senior Vice President of Business Development and Land(7)
Marcia M. MacLeod	58	Senior Vice President of Human Resources and Administration(7)
Michael R. Fiser	47	Senior Vice President of Marketing(7)
Steven G. Natali	57	Senior Vice President of Exploration(7)
J. Kevin Vann	40	Chief Accounting Officer and Controller(7)

(1) At the time of the spin-off, Mr. Armstrong will no longer serve as Chairman of our Board and Mr. Chappel will no longer serve as one of our directors.

(2) As of January 1, 2012, Mr. Chappel will no longer serve as our Chief Financial Officer.

(3) As of January 1, 2012, Mr. Timmermans and Ms. Ewing will no longer serve as officers.

(4) Effective January 1, 2012, Mr. Bender s position will be Senior Vice President, General Counsel and Corporate Secretary.

(5) Effective January 1, 2012, Mr. Sailor s position will be Senior Vice President, Chief Financial Officer and Treasurer.

(6) At the time of the spin-off, Mr. Lowrie will become Chairman of our Board.

(7) Position to be effective January 1, 2012.

Alan S. Armstrong. Mr. Armstrong was named Chairman of our Board in April 2011. Mr. Armstrong has been Chief Executive Officer, President and a Director of Williams since January 3, 2011. From February 2002 until January 2011, he was Senior Vice President Midstream at Williams and acted as President of the Midstream business at Williams. From 1999 to February 2002, Mr. Armstrong was Vice President, Gathering and Processing for Midstream at Williams. From 1998 to 1999 he was Vice President, Commercial Development for Midstream at Williams. As of January 2011, Mr. Armstrong serves as Chairman of the Board and Chief Executive Officer of Williams Partners GP LLC, the general partner of Williams Partners, where he was Senior Vice President Midstream from February 2010 and Chief Operating Officer and a director from February 2005.

We believe that Mr. Armstrong is well qualified to serve as Chairman of our Board. Mr. Armstrong has many years of experience in our industry, including over 25 years of operating and executive experience with Williams, and we believe this experience will be critical to his ability to identify, understand and address challenges and opportunities that we will face. As the current Chief Executive Officer and President of Williams, we believe Mr. Armstrong is uniquely suited to serve as our Chairman as we become a newly public company. Mr. Armstrong also has knowledge and understanding of corporate governance issues through serving as a public company senior executive and board member. Further, we believe that his executive experience dealing with legislators and regulators will make him an excellent resource for our management and other directors.

Ralph A. Hill. Mr. Hill was named Chief Executive Officer in April 2011, and he will be elected as a director prior to the completion of this offering. Prior to becoming our Chief Executive Officer, Mr. Hill was Senior Vice President Exploration and Production and acted as President of the Exploration and Production business at Williams since 1998. He was Vice President and General Manager of Exploration and Production business at Williams from 1993 to 1998, as well as Senior Vice President and General Manager of Petroleum Services at Williams from 1998 to 2003. Mr. Hill has served as the Chairman of the Board and Chief Executive Officer of Apco since 2002. Mr. Hill has served as a director of Petrolera Entre Lomas S.A. since 2003. He joined Williams in June 1981 as a member of a management training program and has worked in numerous capacities within the Williams organization.

We believe Mr. Hill is well qualified to serve as a member of our Board. Mr. Hill has many years of experience in our industry, including executive, operating and international business experience, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we will face. As our Chief Executive officer with intimate knowledge of our business and operations, Mr. Hill will bring a valuable perspective to the Board. Further, we believe that Mr. Hill s experiences of over 30 years with Williams will be advantageous as we become a newly public company.

Donald R. Chappel. Mr. Chappel was named Chief Financial Officer in April 2011, and he will be elected as a director prior to the completion of this offering. Mr. Chappel has been Senior Vice President and Chief Financial Officer of Williams since April 2003. Prior to joining Williams, Mr. Chappel held various financial, administrative, and operational leadership positions. Mr. Chappel is included in Institutional Investor magazine s Best CFOs listing for 2011, 2010, 2008, 2007, and 2006. Mr. Chappel also serves as Chief Financial Officer and a director of Williams Partners GP LLC, the general partner of Williams Partners. Mr. Chappel was Chief Financial Officer, from August 2007, and a director, from January 2008, of the general partner of Williams Pipeline Partners L.P., until its merger with Williams Partners in August 2010. Mr. Chappel is also a director of SUPERVALU Inc.

We believe that Mr. Chappel is well qualified to serve as a member of our Board. Mr. Chappel brings significant experience in finance and accounting, including expertise as a public company senior finance executive, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we will face. Mr. Chappel also has public company director and audit committee experience. Further, we believe that Mr. Chappel s experience as Senior Vice President and Chief Financial Officer at Williams will be advantageous to us as we become a newly public company, and his service as our Chief Financial Officer will allow him to provide his perspective in that capacity to the Board.

Ted T. Timmermans. Mr. Timmermans was named Chief Accounting Officer in April 2011. Mr. Timmermans has been Vice President, Controller and Chief Accounting Officer of Williams since July 2005, and Vice President, Controller and Chief Accounting Officer of Williams Partners GP LLC, the general partner of Williams Partners since September 2005. Mr. Timmermans served as an Assistant Controller of Williams from April 1998 to July 2005. Mr. Timmermans served as Chief Accounting Officer of the general partner of Williams Pipeline Partners L.P., from 2008 until its merger with Williams Partners in August 2010.

James J. Bender. Mr. Bender was named General Counsel and Corporate Secretary in April 2011. Mr. Bender has been Senior Vice President and General Counsel of Williams since December 2002, and General Counsel of Williams Partners GP LLC, the general partner of Williams Partners, since September 2005. Mr. Bender served as the General Counsel of the general partner of Williams Pipeline Partners L.P., from 2007 until its merger with Williams Partners in August 2010. From June 1997 to June 2002, Mr. Bender was Vice President and General Counsel of NRG Energy, Inc. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.

Robyn L. Ewing. Ms. Ewing was named Chief Administrative Officer in April 2011. Ms. Ewing has been Senior Vice President and Chief Administrative Officer of Williams since April 2008. From 2004 to 2008 Ms. Ewing was Vice President of Human Resources at Williams. Prior to joining Williams, Ms. Ewing worked at MAPCO, which merged with Williams in April 1998. She began her career with Cities Service Company in 1976.

Rodney J. Sailor. Mr. Sailor was named Treasurer and Deputy Chief Financial Officer in April 2011. Mr. Sailor has served as Vice President and Treasurer of Williams since July 2005. He served as Assistant Treasurer of Williams from 2001 to 2005 and was responsible for capital restructuring and capital markets transactions, management of Williams liquidity position and oversight of Williams balance sheet restructuring program. From 1985 to 2001, Mr. Sailor served in various capacities for Williams. Mr. Sailor was a director of Williams Partners GP LLC, the general partner of Williams Partners, from October 2007 to February 2010. Mr. Sailor has served as a director of Apco since September 2006.

George A. Lorch. Mr. Lorch will be elected as a director prior to the completion of this offering. Mr. Lorch has been a director of Williams since 2001 and currently serves as a member of Williams Compensation Committee and its Nominating and Governance Committee. Prior to joining our Board, Mr. Lorch will resign from the Williams board of directors. Mr. Lorch is Chairman Emeritus of Armstrong Holdings, Inc., the holding company for Armstrong World Industries, Inc. (a manufacturer and marketer of floors, ceilings, and cabinets). He was the Chief Executive Officer and President of Armstrong World Industries, Inc. from 1993 to 1994 and Chairman of the Board and Chief Executive Officer from 1994 to 2000. From May 2000 to August 2000, he was Chairman of the Board and Chief Executive Officer of Armstrong Holdings, Inc. Mr. Lorch has 37 years of sales and marketing experience at Armstrong, including 17 years of experience as a head of operations, with responsibility for profit and loss statements, balance sheets, and stockholder relations. During his 21 years as a director in varied industries, Mr. Lorch has participated in CEO searches, succession planning, strategy development, takeover defense and offense, and director recruitment, and he has served on dozens of board committees. Mr. Lorch has also completed an executive management course at the Kellogg School of Management at Northwestern University. Mr. Lorch is the non-executive Chairman of the Board of Pfizer, Inc. (a research-based pharmaceutical company) and a director of Autoliv, Inc. (a developer, manufacturer, and supplier of automotive safety systems); HSBC Finance Corporation and HSBC North America Holdings Inc., non-public, wholly-owned subsidiaries of HSBC LLC (a banking and financial services provider); and Masonite (a door manufacturer). Mr. Lorch also serves as an advisor to the Carlyle Group (a private equity firm).

We believe that Mr. Lorch is well qualified to serve as a member of our Board. Mr. Lorch s executive experience provides valuable financial and management experience, including expertise leading a large organization with multi-national operations, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we will face. Mr. Lorch also has knowledge and understanding of the strategy, recruitment, compensation and corporate governance issues that we will face from his extensive experience as a director. Further, we believe Mr. Lorch s experience as a director of Williams will be advantageous to us as we become a newly public company.

William G. Lowrie. Mr. Lowrie will be elected as a director prior to the completion of this offering. Mr. Lowrie has been a director of Williams since 2003 and currently serves as the Chair of Williams Audit Committee and a member of Williams Nominating and Governance Committee. In 1999, Mr. Lowrie retired as Deputy Chief Executive Officer and director of BP Amoco PLC (a global energy company), where he spent his entire 33-year career. At Amoco, Mr. Lowrie held various positions of increasing responsibility, developing expertise in drilling, reservoir engineering, financial analysis of projects, and other skills related to the oil and natural gas exploration, production, and processing businesses. At various times in his Amoco tenure, Mr. Lowrie managed natural gas and natural gas liquids pipeline operations, hedging and other hydrocarbon price risk mitigation functions, international contract negotiations, petroleum product refining and marketing operations, environmental health and safety program design, and the development and execution of a process for managing capital investment projects. Mr. Lowrie also worked closely with all financial functions, internal and external auditors, and industry organizations such as the American Petroleum Institute. From 1995 to 1999, Mr. Lowrie served on the board of Bank One Corporation (now JP Morgan Chase), including on that board s audit committee. He has attended the Executive Program at the University of Virginia. Mr. Lowrie is a director of The Ohio State University Foundation and a trustee of the South Carolina chapter of The Nature Conservancy.

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We believe that Mr. Lowrie is well qualified to serve as a member of our Board. Mr. Lowrie has many years of experience in our industry, including operating, financial and executive experience, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we will face. Mr. Lowrie also has extensive risk-management experience from his time at BP Amoco and from his service on Williams Audit Committee. Further, we believe Mr. Lowrie s experience as a director of Williams will be advantageous to us as we become a newly public company.

Bryan K. Guderian. Mr. Guderian was named Senior Vice President of Operations in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Since 1998, Mr. Guderian has served as Vice President of the Exploration & Production unit of Williams with responsibility for the operational and commercial oversight and management of assigned exploration and production assets in the Marcellus Shale, the San Juan Basin and other basins. Mr. Guderian also has responsibility for overseeing Williams international operations and has served as a director of Apco since 2002 and a director of Petrolera Entre Lomas S.A. since 2003. Mr. Guderian joined Williams in 1991 as a gas marketing representative.

Neal A. Buck. Mr. Buck was named Senior Vice President of Business Development and Land in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Mr. Buck has been Vice President Commercial Operations & Gas Management with Williams Exploration & Production since August 2001. In that capacity, he is responsible for acquisitions and divestitures, planning, gathering and processing contracts, reserves and production reporting and other services. Mr. Buck joined Williams in 1996, and served as Director of Planning and Analysis from March 1998 to August 2001. Prior to joining Williams, Mr. Buck was with Occidental Petroleum Corporation.

Marcia M. MacLeod. Ms. MacLeod was named Senior Vice President of Human Resources and Administration in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Ms. MacLeod has served as Vice President and Chief Information Officer of Williams since July 2008. Since joining Williams in 2000, Ms. MacLeod served as Vice President of Compensation, Benefits and Human Resources Information Services from October 2000 to May 2004 as well as Vice President of Enterprise Business Services from May 2004 to July 2008. Prior to joining Williams, Ms. MacLeod served as Managing Director of Global Compensation and Benefits for Electronic Data Systems. She has held management roles at JC Penney Company and HEB Grocery Company, and has practiced tax and employee benefits law with a firm in Dallas. Ms. MacLeod is also a member of Mott Production LLC, a privately held company holding various oil and gas interests.

Michael R. Fiser. Mr. Fiser was named Senior Vice President of Marketing in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Since May 2008, Mr. Fiser has served as Vice President and Director of Williams Gas Marketing, Inc, with responsibilities including the sales, marketing, transportation management, operations, storage management, trading and hedging of Williams natural gas portfolio. He served as Director for Williams Energy Marketing and Trading and Williams Power from September 1998 to 2008 and was responsible for commercial trading strategies, hedging and logistics. Prior to joining Williams, Mr. Fiser worked at Koch Industries, Inc. in various marketing and trading roles from June 1987 to September 1998.

Steven G. Natali. Mr. Natali was named Senior Vice President of Exploration in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Mr. Natali has served as Williams Vice President of Exploration and Geophysics since 2001. Mr. Natali served as Chief Geophysicist and Vice President of Exploration of Barrett Resources from 1995 until Williams purchase of that company in 2001. Prior to his employment with Barrett Resources, Mr. Natali worked for 12 years as an exploration geophysicist for Amoco Production Company, participating in many of the emerging plays of the Rocky Mountain basins, Oklahoma Spiro Sandstone play and North Slope of Alaska.

J. Kevin Vann. Mr. Vann was named Chief Accounting Officer and Controller in August 2011, to be effective at the earlier of January 1, 2012 or the time of the spin-off. Since June 2007, Mr. Vann has served as Controller for Williams Exploration & Production business unit. He was Controller for Williams Power Company from 2006 to 2007 and Director of Enterprise Risk Management for Williams from 2002 to 2006. In his Controller positions, he was responsible for the development and implementation of internal controls to ensure effective

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financial and business systems, accurate financial statements and the timely provision of appropriate information and analysis to assist in the strategic management of the company. As Director of Enterprise Risk Management, he was responsible for the aggregation and measurement of commodity and credit risk.

Board Composition

Our business and affairs will be managed under the direction of our board of directors. Immediately following the completion of this offering, we expect that at least one member of our board of directors will be independent under applicable rules of the NYSE. Within one year following the completion of this offering, the board of directors will include three independent directors under applicable rules of the NYSE. The directors will have discretion to increase or decrease the size of the board of directors.

Status as a Controlled Company

Upon completion of this offering and prior to the anticipated spin-off of our stock to Williams stockholders, Williams will control a majority of the voting power for the election of our directors, and we will therefore be a controlled company under NYSE corporate governance standards. A controlled company need not comply with NYSE corporate governance rules that require its board of directors to have a majority of independent directors and independent compensation and nominating and corporate governance committees. We intend to avail ourselves of the controlled company exception under the NYSE corporate governance standards. Notwithstanding our status as a controlled company, we will remain subject to the NYSE corporate governance standard that requires us to have an audit committee composed entirely of independent directors. As a result, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, or the listing date, at least two independent directors within 90 days of the listing date and at least three independent directors within one year of the listing date.

If Williams completes a spin-off of all of the shares of our common stock that it owns to its stockholders or holds less than a majority of the voting power for any other reason, we will no longer be a controlled company within the meaning of the NYSE corporate governance standards. Once we cease to be a controlled company, our board of directors will be required to have a compensation committee and a nominating and governance committee, each with at least one independent director. Within 90 days of ceasing to be a controlled company, we will be required to have each of a compensation committee and a nominating and governance committee with a majority of independent directors, and within one year of ceasing to be a controlled company, a majority of our board of directors must be comprised of independent directors.

Board Committees

Audit committee

Prior to completion of this offering, our board of directors will establish an audit committee, composed of three directors. The audit committee will consist of the number of independent directors as required by the applicable NYSE rules within the applicable time periods following the completion of this offering. The board of directors will determine that all of the audit committee members are financially literate.

The audit committee s functions will include providing assistance to the board of directors in fulfilling its oversight responsibility relating to our financial statements and the financial reporting process, compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm, our system of internal controls, the internal audit function, our code of ethical conduct, retaining and, if appropriate, terminating the independent registered public accounting firm, and approving audit and non-audit services to be performed by the independent registered public accounting firm.

In compliance with the NYSE listing standards, our audit committee will annually conduct a self-evaluation to determine whether it is functioning effectively. In addition, the audit committee will prepare the report of the committee required by the rules and regulations of the SEC to be included in our annual proxy statement.

Our board of directors will adopt a written charter for our audit committee, which will be available on our corporate website prior to or upon completion of this offering.

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Other Committees

Because we will be a controlled company within the meaning of the NYSE corporate governance standards, we will not be required to, and will not, have a compensation or nominating and governance committee. While we are a controlled company, Williams nominating and corporate governance committee will identify and evaluate potential candidates for nomination as a director and recommend any such candidates to our board of directors.

Our board of directors may form a compensation committee and/or a nominating and governance committee after the completion of this offering.

Compensation Committee Interlocks and Insider Participation

Initially, compensation recommendations regarding our executive officers may be made by the Williams compensation committee. Our board of directors may appoint a successor compensation committee after the completion of this offering. None of our executive officers serves, or has served during the last completed fiscal year, on the compensation committee or board of directors of any other company that has one or more executive officers serving on our compensation committee or board of directors.

Code of Ethics

In connection with this offering, our board of directors will adopt a Code of Ethics for Senior Officers that applies to our Chief Executive Officer, Chief Financial Officer and Controller, or persons performing similar functions. Our code of ethics will be publicly available on our corporate website. Any waiver of our code of ethics with respect to our Chief Executive Officer, Chief Financial Officer and Controller, or persons performing similar functions may only be authorized by our audit committee and will be disclosed as required by applicable law.

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EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We have yet to establish a compensation committee of our board of directors. As a result, the compensation information provided herein reflects the compensation program established by the compensation committee of Williams board of directors (Committee) in place to compensate Williams officers on December 31, 2010, except as otherwise indicated.

As our compensation program is developed, the Williams board of directors and/or Committee will provide input, analyze and approve WPX Energy s compensation and benefit plans and policies until our compensation committee is formed. To date, the Committee has approved our pay philosophy and our comparator group of companies. Specific compensation and benefit programs for WPX Energy have yet to be developed.

It should be noted that Williams provides generally consistent compensation programs and metrics for all officers across the enterprise. In 2010, an officer working in Williams Exploration & Production business unit, the base group for WPX Energy, had the same long-term incentive and annual incentive award metrics and design as an officer working in any other part of Williams. Therefore, the compensation programs described for the named executive officers of WPX Energy (NEOs) in this Compensation Discussion and Analysis are consistent in form with the compensation program received by officers in the Exploration & Production business unit.

The executive officers who were largely responsible for conducting the business of WPX Energy and for managing the operations of Williams Exploration & Production business unit during 2010 are also executive officers of Williams. For the fiscal year ending December 31, 2010, the Williams executive officers who comprised the executive team for WPX Energy and who are referred to as the NEOs were: Steven J. Malcolm, former Chairman, President and Chief Executive Officer (CEO) of Williams; Donald R. Chappel, Chief Financial Officer of Williams and our Chief Financial Officer; Ralph A. Hill, Senior Vice President Exploration & Production of Williams, and our CEO; James J. Bender, Senior Vice President and General Counsel of Williams and our General Counsel and Corporate Secretary; and Robyn L. Ewing, Senior Vice President and Chief Administrative Officer of Williams and our Chief Administrative Officer.

Objective of Williams Compensation Programs

The role of compensation for Williams is to attract and retain the talent needed to drive stockholder value and to help enable each business of Williams to meet or exceed financial and operational performance targets. The objective of Williams compensation programs is to reward employees for successfully implementing the strategy to grow the business and create long-term stockholder value. To that end, Williams uses relative and absolute Total Shareholder Return (TSR) to measure long-term performance, and Economic Value Added® (EVA® [1])to measure annual performance. Williams believes using both TSR and EVA® to incent and pay NEOs helps ensure that the business decisions made are aligned with the long-term interests of Williams stockholders.

Looking forward While our pay philosophy has been approved by the Committee, the specific design of our long-term incentive, the annual cash incentive, the base pay and benefit plans has yet to be determined.

Williams 2010 Pay Philosophy

Williams pay philosophy throughout the entire organization is to pay for performance, be competitive in the marketplace and consider the value a job provides to Williams. The compensation programs reward NEOs and employees not just for accomplishing goals, but also for how those goals are pursued. Williams strives to reward the right results and the right behaviors while fostering a culture of collaboration and teamwork.

[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co.

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The principles of Williams pay philosophy influence the design and administration of its pay programs. Decisions about how to pay NEOs are based on these principles. The Committee uses several different types of pay that are linked to both long-term and short-term performance in the executive compensation programs. Included are long-term incentives, annual cash incentives, base pay and benefits. The chart below illustrates the linkage between the types of pay used and the pay principles.

Williams Pay Principles	**Long-term Incentives**	**Annual Cash Incentives**	**Base Pay**	**Benefits**
Pay should reinforce business objectives and values	ü	ü	ü	
A significant portion of an NEO s total pay should be variable based on performance	ü	ü		
Incentive pay should balance long-term, intermediate and short-term performance	ü	ü		
Incentives should align interest of NEOs with stockholders	ü	ü		
Pay opportunity should be competitive	ü	ü	ü	ü
A portion of pay should be provided to compensate for the core activities required for performing in the role			ü	ü
Pay should foster a culture of collaboration with shared focus and commitment to Williams	ü	ü		

Looking Forward Our pay philosophy, which will serve to influence the design and delivery of our pay programs, has been approved by the Committee. Our approved pay philosophy is substantially the same as Williams pay philosophy.

Williams 2010 Compensation Summary

In 2010, Williams, including its Exploration and Production business unit, continued to focus on creating stockholder value by delivering solid financial and operational performance. The effects of the economic recession during late 2008 and 2009 eased during 2010. Crude oil and NGL prices returned to attractive levels, but natural gas prices remained low. Williams continued to respond to the changing landscape and completed a number of significant business transactions as detailed on page 119. Williams took several actions, described below, to ensure that its executive pay program remains affordable and competitive in the current market and after market conditions improve.

Williams 2010 Pay Decisions

As indicated above, significant consideration was given to the need to balance Williams pay philosophy and practices with affordability and sustainability. Williams continued to grant long-term incentives in the form of performance-based restricted stock units (RSUs), stock options and time-based RSUs in 2010 to emphasize its commitment to pay for performance.

Consistent with its commitment to provide a meaningful connection between pay and performance, Williams has granted performance-based RSUs to NEOs since 2004. The performance-based RSUs granted in 2008 for the 2008-2010 performance period did not meet threshold targets set at the beginning of the period as a result of the global economic crisis. The challenging performance targets established in 2008 for the three-year performance period included economic assumptions that could not anticipate the significant decline in economic conditions. In accordance with the design of the awards, these awards were cancelled. This is the second consecutive year the performance-based RSUs were not earned. This resulted in each NEO losing a significant portion of pay that was targeted for 2007-2009 and 2008-2010.

It is important to note that the Summary Compensation Table displays a value for equity awards on the date of grant. This approach does not reflect the actual realized value associated with equity award grants. While the grant date values make it appear that NEOs pay has been fairly consistent in recent years, the value realized by the NEOs has significantly declined in recent years due to Williams pay for performance philosophy.

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Historically, Williams sets performance targets for its Annual Incentive Program (AIP) during the first quarter. The targets established in 2010 anticipated an improving economic environment and required significantly improved performance over 2009. While EVA® performance exceeded 2009 levels, the 2010 AIP results paid less than 2009 due to higher 2010 performance targets.

With respect to base salary, Mr. Malcolm did not receive a base pay increase in 2009 or 2010. The remaining NEOs did not receive a base pay increase in 2009 and received a two percent base pay increase in 2010, other than Ms. Ewing who received a 3.5% increase in 2010.

Williams Plan Design Decisions

The Committee regularly reviews Williams existing pay programs to ensure Williams ability to attract and retain the talent needed to deliver the strong financial and operating performance necessary to create stockholder value while ensuring its program effectively links pay to the performance of Williams. As part of this process in 2010, the Committee reached several important decisions. The Committee decided to continue awarding a significant portion of long-term incentive awards in the form of performance-based restricted stock units (RSUs). The metric for these awards utilizes absolute and relative TSR. NEOs will earn their targeted performance-based RSUs for the 2010 to 2012 period only if Williams delivers positive absolute TSR and also achieves solid TSR in relation to the Williams comparator group of companies. The Committee believes it is important to include both relative and absolute TSR to ensure that results are impacted by the absolute TSR actually delivered to stockholders, as well as the company s performance relative to comparator companies. Williams commitment to these awards combined with the utilization of both relative and absolute TSR metrics demonstrates the emphasis on linking pay to long-term performance and aligning its pay programs with the interest of stockholders.

Williams continues to deliver a significant portion of equity in performance-based awards and stock options because these awards have the strongest alignment to stockholders. Shown below is the long-term incentive mix for the NEOs under Williams compensation program for 2010.

	Mr. Malcolm	**Other NEOs**
Performance-Based RSUs	50%	35%
Stock Options	50%	30%
Time-Based RSUs	0%	35%

As to Williams AIP, EVA® improvement remained the performance metric in 2010. The difficult economic and commodity price environment made establishing a target level of performance very challenging. In anticipation of an improving economic environment, the Committee approved a 2010 EVA® performance target that was substantially higher than targets established for 2009. The Committee also continued a decision reached in 2009 to require that the AIP performance necessary to move from threshold to target was doubled from 2008 levels. Likewise, the performance required to move from target to stretch was doubled from 2008 levels. This design attempts to keep the AIP as a meaningful performance incentive throughout the year while ensuring a payout significantly above target only occurs if Williams significantly exceeds established performance targets.

Mitigating Risk

After a thorough review and analysis, it was determined that the risks arising from Williams compensation policies and practices are not reasonably likely to have a material adverse effect on Williams.

Williams Compensation Recommendation and Decision Process

Role of Williams Management

In order to make pay recommendations, management provides the Williams CEO with data from the annual proxy statements of companies in Williams comparator group along with pay information compiled from nationally recognized executive and industry related compensation surveys. The survey data is used to confirm that pay practices among companies in the comparator group are aligned with the market as a whole.

Role of Williams CEO

Before recommending base pay adjustments and long-term incentive awards to the Committee, Williams CEO reviews the competitive market information related to each of Williams other named executive officers while also considering internal equity and individual performance.

For the annual cash incentive program, the Williams CEO s recommendation is based on EVA® attainment with a potential adjustment for individual performance. Individual performance includes business unit EVA® results for the business unit leaders, achievement of business goals and demonstrated key leadership competencies (for more on leadership competencies, see the section entitled Base Pay in this Compensation Discussion and Analysis). The modifications made are fairly modest. For 2010 the adjustments made to the NEOs annual cash incentive awards were in total less than 5%.

Role of the Other NEOs

The NEOs, and Williams other named executive officers, have no role in setting compensation for any of the NEOs.

Role of Williams Compensation Committee

For all NEOs, except the Williams CEO, the Committee reviews the Williams CEO s recommendations, supporting market data and individual performance assessments. In addition, the Committee s independent compensation consultant, Frederic W. Cook & Co., Inc., reviews all of the data and advises on the reasonableness of the Williams CEO s pay recommendations.

For the Williams CEO, the Williams board of directors meets in executive session without management present to review the Williams CEO s performance. In this session, the Williams board of directors reviewed:

- Evaluations of the Williams CEO completed by the board members and the executive officers (excluding the Williams CEO);
- The Williams CEO s written assessment of his/her own performance compared with the stated goals; and
- EVA® performance of the Company relative to established targets as well as the financial and safety metrics presented as a supplement to EVA® performance.

The Committee uses these evaluations and competitive market information provided by its independent compensation consultant to determine the Williams CEO s long-term incentive amounts, annual cash incentive target, base pay and any performance adjustments to be made to the Williams CEO s annual cash incentive payment.

Role of the Independent Compensation Consultant

Frederic W. Cook & Co., Inc. assists the Committee in determining or approving the compensation for Williams executive officers. Frederick W. Cook & Co., Inc. will serve as the independent compensation consultant to the Committee as the Committee provides input and analyzes and approves our compensation and benefit plans and policies until our compensation committee is formed.

To assist the Committee in discussions and decisions about compensation for the NEOs, the Committee s independent compensation consultant presents competitive market data that includes proxy data from the approved Williams comparator group and published compensation data, using the same surveys and methodology used for the other

NEOs (described in the Role of Management section in this Compensation Discussion and Analysis). The Williams comparator group is developed by the Committee s independent compensation consultant, with input from management, and is approved by the Committee.

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2010 Williams Comparator Group

How Williams Uses its Comparator Group

Williams refers to publicly available data showing how much Williams comparator group pays, as well as how that pay is divided among base pay, annual incentive, equity and other forms of compensation. This allows the Committee to ensure competitiveness and appropriateness of proposed compensation packages. When setting pay, the Committee uses market median information of Williams comparator group, as opposed to market averages, to ensure that the impact of any unusual events that may occur at one or two companies during any particular year is diminished from the analysis. If an event is particularly unusual and surrounds unique circumstances, the data is completely removed from the assessment.

Composition of the Williams Comparator Group

Each year the Committee reviews the prior year s Williams comparator group to ensure that it is still appropriate. Williams last made changes to this group for 2009. Williams comparator group focuses on companies that work in the same industry segment and reflect where Williams competes for business and talent. The 2010 Williams comparator group for 2010 included 20 companies, which comprise a mix of both direct competitors to Williams and companies whose primary business is similar to at least one of Williams business segments. These companies are included in the chart below under the column entitled Williams 2010 Comparator Company Group.

Characteristics of Williams Comparator Group

Companies in Williams comparator group have a range of revenues, assets and market capitalization. Business consolidation and unique operating models today create some challenges in identifying comparator companies. Accordingly, Williams takes a broader view of comparability to include organizations that are similar to Williams in some, but not all, respects. This results in compensation that is appropriately scaled and reflects comparable complexities in business operations.

Composition of Our Comparator Group

Our comparator company group approved by the Committee is provided below. This group is anticipated to be used in making our compensation decisions that we currently expect to be applied beginning in 2012.

Company Name	Williams 2010 Comparator Company Group	Our Comparator Company Group
Anadarko Petroleum Corp.	X	
Apache Corp.	X	
Cabot Oil & Gas Corp.		X
Centerpoint Energy Inc.	X	
Chesapeake Energy Corp.	X	X
Cimarex Energy Corp.		X
Devon Energy Corp.	X	X
Dominion Resources Inc.	X	
El Paso Corp.	X	

EOG Resources Inc.	X	X
EQT Corp.	X	
Forest Oil Corp.		X
Hess Corp.	X	
Murphy Oil Corp.	X	

Company Name	Williams 2010 Comparator Company Group	Our Comparator Company Group
Newfield Exploration Co.		X
NiSource Inc.	X	
Noble Energy Inc.	X	X
Oneok Inc.	X	
Petrohawk Energy Corp.		X
Pioneer Natural Resources Co.		X
Plains All American Pipeline	X	
QEP Resources Inc.		X
Questar Corp.	X	
Range Resources Corp.		X
Sandridge Energy Inc.		X
Sempra Energy	X	
SM Energy Co.		X
Southern Union Co.	X	
Southwestern Energy Co.		X
Spectra Energy Corp	X	
Ultra Petroleum Corp.		X
XTO Energy Inc. (acquired by ExxonMobil removed)	X	

Characteristics of Our Comparator Group

Our comparator group focuses on companies that work in the same industry segment and reflect where we compete for business and talent. Companies in the comparator group have a range of revenues, assets and market capitalization as well as a range of operational measures such as production and reserves. Our comparator group is appropriately scaled and these companies primary business is similar to ours and is subject to similar economic circumstances.

Williams Pay Setting Process

Setting pay for our NEOs historically has been an annual process that occurs during the first quarter of the year. The Committee completes a review to ensure that pay is competitive, equitable and encourages and rewards performance.

The compensation data of Williams comparator group disclosed in proxy statements is the primary market data used when benchmarking the competitive pay of the NEOs. Aggregate market data obtained from recognized third-party executive compensation survey companies (e.g. Towers Watson, Mercer, AonHewitt) is used to supplement and validate Williams comparator group market data for these executive officers. Typically, the Committee is presented with a range of annual revenues of the companies whose data is included in the aggregate analysis provided by the third party survey, but does not know the identities of the specific companies included.

Although the Committee reviews relevant data as it designs compensation packages, setting pay is not an exact science. Since market data alone does not reflect the strategic competitive value of various roles within Williams, internal pay equity is also considered when making pay decisions. Because Williams applies an enterprise-wide perspective to promote collaboration and ensure overall success, paying the executive officers equitably is important. Other considerations when making pay decisions for the NEOs include historical pay and tally sheets that include annual pay and benefit amounts, wealth accumulated over the past five years and the total aggregate value of the NEOs equity awards and holdings.

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When setting pay, Williams determines a target pay mix (distribution of pay among long-term incentives, annual incentives, base pay and other forms of compensation) for the NEOs. Consistent with Williams pay-for-performance philosophy, the actual amounts paid, excluding benefits, are determined based on Williams and individual performance. The following table provides the 2010 target pay mix by NEO.

	2010 Target Pay Mix by NEO			
	Base Salary	Annual Incentive	Long-Term Incentive	Total
Mr. Malcolm	14%	14%	72%	100%
Mr. Chappel	20%	15%	65%	100%
Mr. Hill	19%	13%	68%	100%
Mr. Bender	23%	15%	62%	100%
Ms. Ewing	22%	14%	64%	100%

Game Plan for Growth

Williams goal for 2010 was to grow the natural gas-based businesses in order to generate superior value for investors in Williams and Williams Partners. The performance of the NEOs and other employees is measured by progress made towards the Game Plan for Growth goals. Individual adjustments within Williams annual cash incentive program are based on each NEO s contributions to the Game Plan for Growth. The goals defined in the Game Plan for Growth include:

Invest in Growth

Enhance Williams relationships with customers so that Williams continues to grow its competitive advantage and earn recognition for the reliable service and value that is essential to their success.

Invest in Williams businesses in ways that grow EVA®, earnings and cash flows for Williams and Williams Partners; meet Williams customers needs; and enhance Williams competitive position.

Pursue additional investment opportunities in new and emerging basins to capture significant, strategic, long-lived growth.

Expand Williams intellectual, operational and leadership capacities so that Williams can successfully grow and develop high-performing employees and businesses.

Support Williams Growth

Comply with applicable laws and regulations.

Continuously improve Williams safety and environmental compliance performance in all of Williams operations.

Assess and manage risks effectively; take appropriate, well-considered risks in order to create value. Exercise financial discipline so that Williams and Williams Partners financial condition is strong and credit ratings are investment-grade.

Deliver the Growth

Achieve or exceed Williams EVA®, earnings and cash flow goals. Also achieve attractive growth in value for Williams and Williams Partners investors.

Openly engage with communities, vendors and other stakeholders crucial to Williams success so that Williams grows the competitive advantage we enjoy as a preferred partner.

Operate the business in a way that grows Williams reputation as a leader in environmental stewardship.

During 2010, Williams made significant strides toward achieving Williams Game Plan for Growth. The following are some of the most impactful 2010 accomplishments:

- Completed the transformation of Williams Partners to a large diversified master limited partnership with reliable access to capital markets. This was accomplished through:
  - Strategic asset drop-downs from Williams to Williams Partners; and
  - The merger of Williams Partners and Williams Pipeline Partners L.P.
- Completed significant asset acquisitions in the Marcellus Shale. All of Williams businesses have a strategic presence in the Marcellus Shale allowing Williams to leverage the strengths of each business unit;
- Invested $2.8 billion in drilling activity and acquisitions in Williams Exploration & Production business. This included $1.7 billion related to acquisitions in the Bakken and Marcellus Shale areas. The Bakken Shale transaction creates more diversification in Williams Exploration and Production business by expanding the long-term crude oil portfolio;
- Invested $1 billion in capital and investment expenditures in the midstream businesses and invested $473 million in capital expenditures in Williams gas pipelines business in 2010;
- Expanded ownership of the Overland Pass Pipeline;
- Maintained Williams investment grade credit rating while achieving an upgrade of Williams Partners to an investment grade credit rating; and
- In addition to continuing to expand Williams natural gas businesses and drive stockholder value, Williams was recognized for its efforts to make Williams a great place to work for its employees;
  - The Houston Business Journal recognized Williams as a Best Place to Work in Houston among companies not based in Houston. This was the third year in a row Williams was recognized on the Best Place to Work in Houston list;
  - Utah Business magazine named Williams as a finalist in its Best Companies to Work for program, where Williams was recognized as one of the four best medium-sized companies in Utah for the second year in a row;
  - OKCBiz magazine recognized Williams on its Best Places to Work in Oklahoma list for the third year in a row; and
  - Tulsa Business Journal s Economic Development Impact Awards recognized Williams as a finalist for the Best Workplace for Young Professionals.

How Williams Determines the Amount for Each Type of Pay

Long-term incentives, annual cash incentives, base pay and benefits accomplish different objectives.

Long-Term Incentives

Williams awards long-term incentives to reward performance and align NEOs with long-term stockholder interests by providing NEOs with an ownership stake in Williams, encouraging sustained long-term performance and providing an important retention element to their compensation program. Long-term incentives are provided in the form of equity and may include performance based RSUs, stock options and time-based RSUs.

To determine the value for long-term incentives granted to an NEO each year, Williams considers the following factors:

the proportion of long-term incentives relative to base pay;

the NEO s impact on Williams performance and ability to create value;

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long-term business objectives;

awards made to NEOs in similar positions within Williams comparator group of companies

the market demand for the NEO s particular skills and experience;

the amount granted to other NEOs in comparable positions at Williams;

the NEO s demonstrated performance over the past few years; and

the NEO s leadership performance.

The allocation of the long-term incentive program for 2010 is shown on page 118. The long-term incentive mix for the NEOs is shown on page 114.

The primary objectives for each type of equity awarded are shown below. The size of the circles in the chart indicates how closely each equity type aligns with each objective.

Equity type and Performance Drivers	Stockholder alignment	Stock ownership	Drives operating and financial performance	Retention Incentive
Performance-Based RSUs Absolute and Relative TSR	l	l	l	
Stock Options Stock Price Appreciation	l	l	l	
Time-Based RSUs Stock Price Appreciation	l	l		l

2010 Performance-Based RSUs

Performance-based RSU awards further strengthen the relationship between pay and performance and over time will more closely link the long-term pay of the NEOs to the experience of Williams long-term stockholders.

Williams believes it is important to measure TSR on both an absolute and a relative basis. In absolute terms, Williams wants to ensure it is delivering a responsible return to stockholders. Additionally, Williams believes awards should be influenced by how TSR compares to the TSR of companies in Williams comparator group. Shown in the chart below are the absolute and relative TSR targets for the performance-based restricted stock unit awards for the 2010 to 2012 performance period and the continuum that will determine the resulting potential payout level:

2008 Performance-Based RSUs

The performance cycle for Williams 2008 performance-based RSUs ended in 2010. As discussed earlier, Williams did not attain threshold performance during the three-year period as a result of the global economic crisis. No performance-based RSU awards that were granted in 2008 were paid out under this plan. This resulted in each NEO losing a significant portion of pay that was targeted for 2008-2010. The performance goals for this award were set during a less volatile time based on market guidance and expectations for

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Williams performance at that time. The following is a chart of the threshold, target and stretch goals that were established in early 2008.

EVA® (Millions)	**Payout Level as a % of Target (Attainment %)**
$191	Threshold (where incentives start to be earned)
$299	**100%**
$407	200%

Stock Option Awards

For recipients, stock options have value only to the extent the price of the common stock is higher on the date the options are exercised than it was on the date the options were granted.

Time-Based RSUs

Williams uses this type of equity to retain executives and to facilitate stock ownership. The use of time-based RSUs is also consistent with the practices of Williams comparator group of companies.

Grant Practices

Historically, the Committee typically approves the annual equity grant in February or early March of each year shortly after the annual earnings release. The grant date for awards is on or after the date of such approval to ensure the market has time to absorb material information disclosed in the earnings release and reflect that information in the stock price.

The grant date for off-cycle grants for individuals who are not Williams executive officers, for reasons such as retention or new hires, is the first business day of the month following the approval of the grant. By using this consistent approach, Williams removes grant timing from the influence of the release of material information.

Looking Forward We intend to establish an equity plan prior to completion of this offering. The design of the plan and the form, terms and conditions of future long-term incentive awards available for grant thereunder have not been determined at this time.

Annual Cash Incentives

Williams provides annual cash incentives to encourage and reward NEOs for making decisions that improve Williams performance as measured by EVA®. EVA® measures the value created by a company. Simply stated, it is the financial return in a given period less the capital charge for that period. The calculation used is as follows:

EVA®	=	Adjusted Net Operating Profits after Taxes (NOPAT)	<u>*Less*</u>	Adjusted Capital Charge (the amount of capital invested by Williams multiplied by the cost of capital)

Generating profits in excess of both operating and capital costs (debt and equity) creates EVA®. If EVA® improves, value has been created. The objectives of the EVA® -based incentive program are to:

Motivate and incent management to choose strategies and investments that maximize long-term stockholder value;

Offer sufficient incentive compensation to motivate management to put forth extra effort, take prudent risks and make tough decisions to maximize stockholder value;

Provide sufficient total compensation to retain management; and

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Limit the cost of compensation to levels that will maximize the wealth of current stockholders without compromising the other objectives.

The EVA® Calculation

EVA® is first calculated as NOPAT less Capital Charge. Williams incentive program allows for the Committee to make adjustments to EVA® calculations to reflect certain business events. After studying companies that utilize EVA® as an incentive measure, Williams determined that it is standard practice to make adjustments to EVA® calculations to create better alignment with stockholders.

When determining which adjustments are appropriate, Williams is guided by the principle that incentive payments should not result in unearned windfalls or impose undue penalties. In other words, Williams makes adjustments to ensure NEOs are not rewarded for positive results they did not facilitate nor are they penalized for certain unusual circumstances outside their control. Williams believes the adjustments improve the alignment of incentives with stockholder value creation and ensure EVA® is an incentive measure that effectively encourages NEOs to take actions to create value for stockholders. The categories of potential adjustments to the EVA® calculation are:

Gains, losses and impairments;

Mark-to-market, commodity price collar and construction work-in-progress; and

Other unusual items that could result in unearned windfalls or undue penalties to NEOs such as certain litigation matters and natural disasters.

Williams management regularly reviews with the Committee a supplemental scorecard reflecting Williams segment profit, earnings per share, cash flow from operations and safety to provide updates regarding Williams performance as well as to ensure alignment between these measures and EVA®. This scorecard provides the Committee with additional data to assist in determining final AIP awards. There is strong correlation between Williams EVA® performance and other metrics included on the supplemental scorecard.

The Committee s independent compensation consultant annually compares Williams relative performance on various measures, including total stockholder return, earnings per share and cash flow, with Williams comparator group of companies. The Committee also uses this analysis to validate the reasonableness of the EVA® results.

Annual Cash Incentives Target

The starting point to determine annual cash incentive targets (expressed as a percent of base pay) is competitive market information, which gives Williams an idea of what other companies target to pay in annual cash incentives for similar jobs. Williams also considers the internal value of each job i.e., how important the job is to executing its strategy compared to other jobs in Williams before the target is set for the year. The annual cash incentive targets as a percentage of base pay for the NEOs in 2010 were as follows:

Mr. Malcolm	100%
Mr. Chappel	75%
Other NEOs	65%

Annual Cash Incentives Actual

For NEOs, the annual cash incentive program is funded when Williams attains an established level of EVA® performance. Applying EVA® measurement to this annual cash incentive process encourages management to make business decisions that help drive long-term stockholder value. To determine the funding of the annual cash incentive, Williams uses the following calculation for each NEO:

Base Pay received in 2010	X	Incentive Target %	X	EVA® Goal Attainment %

Actual payments may be adjusted upwards to recognize individual performance that exceeded expectations, such as success toward the Game Plan for Growth and individual goals and successful demonstration of the leadership competencies discussed in the Base Pay section on page 124. Payments may also be adjusted downwards if performance warrants.

How Williams Sets the EVA® Goals

Setting the EVA® goals for the annual cash incentive program begins with internal budgeting and planning. This rigorous process includes an evaluation of the challenges and opportunities for Williams and each of its business units. The key steps are as follows:

- Business and financial plans are submitted by the business units and consolidated by the corporate planning department.

- The business and financial plans are reviewed and analyzed by Williams chief executive officer, chief financial officer and other named executive officers.

- Using the plan guidance, Williams management establishes the EVA® goal and recommends it to the Committee.

- The Committee reviews, discusses and makes adjustments as necessary to management s recommendations and sets the goal at the beginning of each fiscal year.

- Thereafter, progress toward the goal is regularly monitored and reported to the Committee throughout the year.

2010 EVA® Goal for the Annual Cash Incentive Program

The attainment percentage of EVA® goals results in payment of annual cash incentives along a continuum between threshold and stretch levels, which corresponds to 0% through 250% of the NEO s annual cash incentive target. The chart below shows the EVA® improvement goals for the 2010 annual cash incentive and the resulting payout level. It is important to note that setting the EVA® goal for 2010 was again challenging considering the uncertain economic and commodity price environment. The EVA® goal established in 2010 was more challenging than the 2009 EVA® goal, reflecting an anticipated improvement in economic conditions.

EVA® (Millions)	**Payout Level as a % of Target (Attainment %)**
($563)	Threshold (where incentives start to be earned)
($347)	**100%**
($131)	200%

As noted, EVA® considers both financial earnings and a cost of capital in measuring performance. The two main components of EVA® are NOPAT and a charge for the cost of capital. EVA®, like other performance metrics, has been impacted by the economic environment. NOPAT improved from 2009, but fell slightly below the 2010 plan while the 2010 charge for the cost of capital was better than 2009 and better than plan. As a result of the NOPAT and capital charge changes, total EVA® improved significantly from 2009 but was only modestly above the 2010 plan target.

Based on EVA® performance relative to the established goals, the Committee certified performance results of ($337) million in EVA® and approved payment of the annual cash incentive program at 105% of target.

Looking Forward We intend to establish an annual cash incentive program to reward our executive officers. At this time, the design of the program, including the target opportunity and the performance metric(s), has not been determined.

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Base Pay

Base pay compensates NEOs for carrying out the duties of their jobs, and serves as the foundation of Williams pay program. Most other major components of pay are set based on a relationship to base pay, including annual and long-term incentives and retirement benefits.

Base pay for NEOs is set considering the market median, with potential individual variation from the median due to experience, skills and sustained performance of the individual as part of Williams pay-for-performance philosophy. Performance is measured in two ways: through the Right Results obtained in the Right Way. Right Results considers the NEOs success in attaining their annual goals as they relate to the Game Plan for Growth, business unit strategies and personal development plans. Right Way reflects the NEOs behavior as exhibited through Williams leadership competencies. The following table contains these competencies grouped within Williams five leadership areas.

MODEL THE WAY	**INSPIRE A SHARED VISION**	**CHAMPION INNOVATION**	**LEVERAGE TALENT**	**OPTIMIZE BUSINESS PERFORMANCE**
Caring About People	Enterprise Perspective	Change Leadership	Building Effective Teams	Business Acumen
Integrity	Vision and Strategic Perspective	Entrepreneurial Spirit	Communication	Customer and Market Focus
Loyalty and Commitment		Promoting Diversity and Creativity	Developing People Resources	Decision Making
		Willingness to Take Risks	Empowering Others	Drive for Results
			Managerial Courage	Functional/Technical Skills
			Motivating and Inspiring Others	

Looking Forward Our pay philosophy and comparator company group has been determined. This philosophy along with comparator company pay information will influence the base pay decisions of our executive officers. We currently expect this to be applied beginning in 2012.

Benefits

Consistent with Williams philosophy to emphasize pay for performance, NEOs receive very few perquisites (perks) or supplemental benefits. They are as follows:

> *Retirement Restoration Benefits.* All NEOs participate in Williams qualified retirement program on the same terms as other Williams employees. Williams offers a retirement restoration plan to NEOs to maintain a proportional level of pension benefits to officers as provided to other employees. The Code limits qualified pension benefits based on an annual compensation limit. For 2010, the limit was $245,000. Any reduction in an NEO s pension benefit in the tax-qualified pension plan due to this limit is made up for (subject to a cap) in the unfunded restoration retirement plan. Benefits for NEOs are calculated using the same benefit formula as that used to calculate benefits for all employees in the qualified pension plan. The value of pay in the form of stock option or other equity is not used in the formula to calculate benefits under the pension plan or restoration plan for NEOs, which is consistent with the treatment for all employees. Additionally, Williams does not provide a nonqualified benefit related to the qualified 401(k) defined contribution retirement plan.

Financial Planning Allowance. Williams offers financial planning to the NEOs to provide expertise on current tax laws with personal financial planning and preparations for contingencies such as death and disability. In addition, by working with a financial planner, executive officers gain a better understanding of and appreciation for the programs Williams provides, which helps to maximize the retention and engagement aspects of the dollars Williams spends on these programs.

Home Security. Williams paid 2010 home security system and monitoring fees for its former CEO, Mr. Malcolm.

Personal Use of Williams Company Aircraft. Williams provides limited personal use of Williams company aircraft at the Williams CEO s discretion. There was limited personal use of Williams company aircraft by the NEOs in 2010 and the details are provided in the footnote to the Summary Compensation Table.

Event Center. Williams has a suite and club seats at an event center that were purchased for business purposes. If it is not being used for business purposes, Williams makes them available to all employees, including the NEOs, as a form of reward and recognition.

Executive Physicals. The Committee approved physicals for the NEOs beginning in 2009. Executive officer physicals align with Williams wellness initiative as well as assist Williams in mitigating risk. These physicals reduce vacancy succession risk because they help to identify and prevent issues that would leave a role vacated unexpectedly.

Looking Forward Our pay philosophy has been determined. This information and competitive market information will influence the design of our benefits program. The form of these designed benefit programs will influence the offering of any supplemental benefits. Any perquisites to be offered have not been defined at this time.

Additional Components of Williams Executive Compensation Program

In addition to establishing the pay elements described above, Williams has adopted a number of policies to further the goals of the executive compensation program, particularly with respect to strengthening the alignment of NEOs interests with stockholder long-term interests.

Recoupment Policy

In 2008, the Committee approved a recoupment policy to allow Williams to recover incentive-based compensation from executive officers in the event Williams is required to restate the financial statements due to fraud or intentional misconduct. The policy provides the Board discretion to determine situations where recovery of incentive pay is appropriate.

Stock Ownership Guidelines

All NEOs must hold an equity interest in Williams. The chart below shows the NEO stock ownership guidelines, which have been in effect since 2005:

	Holding Requirement as a multiple of Base Pay		
Position	**2010**	**2011**	**Time Frame for Compliance**
Mr. Malcolm	5	6	5 Years
Other NEOs	3	3	5 Years

Annually the Committee reviews the guidelines for competitiveness and alignment with best practice and monitors the NEOs progress toward compliance. The Committee increased the Williams CEO s ownership guideline from five times base pay to six times base pay beginning in 2011. Shares owned outright and unvested performance-based and time-based RSUs count as owned for purposes of the program. Stock options are not included. The Committee maintains discretion to modify the guidelines in special circumstances of financial hardship such as illness of the NEO or a family member.

Derivative Transactions

Williams insider trading policy applies to transactions in positions or interests whose value is based on the performance or price of the common stock. Because of the inherent potential for abuse, Williams prohibits officers, directors and certain key employees from entering into short sales or use of equivalent derivative securities.

Accounting and Tax Treatment

Williams considers the impact of accounting and tax treatment when designing all aspects of pay, but the primary driver of its program design is to support its business objectives. Stock options and performance-based RSUs are intended to satisfy the requirements for performance-based compensation as defined in Section 162(m) of the Code and are therefore considered a tax deductible expense. Time-based RSUs do not qualify as performance-based and may not be fully deductible.

Williams annual cash incentive program satisfies the requirements for performance-based compensation as defined in Section 162(m) of the Code and is therefore a tax deductible expense. For payments under Williams annual cash incentive program to be considered performance-based compensation under Section 162(m), the Committee can only exercise negative discretion relative to actual performance when determining the amount to be paid. In order to ensure compliance with Section 162(m), the Committee has established a target in excess of the maximum individual payout allowed to Williams named executive officers under the annual cash incentive program. Reductions are made each year and are not a reflection of the performance of the Williams named executive officers but rather ensure flexibility with respect to paying based upon performance.

Employment Agreements

Williams does not enter into employment agreements with the NEOs and can remove an NEO when it is in the best interest of the Company.

Termination and Severance Arrangements

The NEOs are not covered under a severance plan. However the Committee may exercise judgment and consider the circumstances surrounding each departure and may decide a severance package is appropriate. In designing a severance package, the Committee takes into consideration the NEO s term of employment, past accomplishments, reasons for separation from Williams and competitive market practice. The only pay or benefits an employee has a right to receive upon termination of employment are those that have already vested or which vest under the terms in place when an award was granted.

Rationale for Change in Control Agreements

Williams change in control agreements, in conjunction with the NEOs RSU agreements, provide separation benefits for the NEOs. Williams program includes a double trigger for benefits and equity vesting. This means there must be a change in control of Williams and the NEO s employment must terminate prior to receiving benefits under the agreement. While a double trigger for equity is not the competitive norm of Williams comparator group, this practice creates security for the NEOs but does not provide an incentive for NEOs to leave Williams. The program is designed to encourage the NEOs to focus on the best interests of Williams stockholders by alleviating their concerns about a possible detrimental impact to their compensation and benefits under a potential Williams change in control, not to provide compensation advantages to NEOs for executing a transaction.

The Committee reviews Williams change in control benefits annually to ensure they are consistent with competitive practice and aligned with Williams compensation philosophy. As part of the review, calculations are performed to determine the overall program costs to Williams if a change in control event were to occur and all covered NEOs were terminated as a result. An assessment of competitive norms including the reasonableness of the elements of compensation received is used to validate benefit levels for a change in control. In reviewing the change in control program in 2010 and 2011, the Committee concluded that certain changes to the benefits provided are appropriate. The Committee approved eliminating the excise tax gross-up provision from the change in control program. The Committee opted to provide a best net provision providing NEOs with the better of their after-tax benefit capped at the safe harbor amount or their benefit paid in full subjecting them to possible excise tax payments. Therefore, in 2011 Williams provided the one year notice required by the NEOs change in control agreements in order to effect the change in 2012. After this provision is implemented, Williams will no longer provide additional compensation to address excise taxes. The Committee continues to believe that offering a change in control program is appropriate and critical to attracting and retaining executive talent and keeping them aligned with Williams stockholder interests in the event of a change in control of Williams.

The following chart details the benefits received if an NEO were to be terminated or resigned for a defined good reason following a change in control as well as an analysis of those benefits as it relates to Williams, stockholders and the NEO. Please also see the Change in Control Agreements section below for further discussion of Williams change in control program.

Change in Control Benefit	**What does the benefit provide to Williams and stockholders?**	**What does the benefit provide to the NEO?**
Multiple of 3x base pay plus annual cash incentive at target	Encourages NEOs to remain engaged and stay focused on successfully closing the transaction.	Financial security for the NEO equivalent to three years of continued employment.
Accelerated vesting of stock awards	An incentive to stay during and after a change in control. If there is risk of forfeiture, NEOs may be less inclined to stay or to support the transaction.	The NEOs are kept whole, if they have a separation from service following a change in control.
Up to 18 months of medical or health coverage through COBRA	This is a minimal cost to Williams that creates a competitive benefit.	Access to health coverage.
3x the previous year s retirement restoration allocation	This is a minimal cost to Williams that creates a competitive benefit.	May allow those NEOs who are nearing retirement to receive a cash payment to make up for lost allocations due to a change in control.
Reimbursement of legal fees to enforce benefit	Keeps NEOs focused on Williams and not concerned about whether the acquiring company will honor commitments after a change in control.	Security during a non-stable period of time.
Outplacement assistance	Keeps NEOs focused on supporting the transaction and less concerned about trying to secure another position.	Assists NEOs in finding a comparable executive position.

Looking Forward We have yet to determine the extent to which any of these programs may be provided to our executive officers.

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Our Equity Plans Following this Offering

After the completion of this offering, we will have an equity incentive plan and an employee stock purchase plan, which are summarized below.

2011 Incentive Plan

The following is a summary of the material terms of the WPX Energy, Inc. 2011 Incentive Plan, which is referred to as the 2011 Incentive Plan. The 2011 Incentive Plan was adopted on , 2011 by our board of directors. This description is not complete. For more information, we refer you to the full text of the 2011 Incentive Plan, which we filed as an exhibit to the registration statement of which this prospectus forms a part.

The 2011 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights (SARs), restricted stock, restricted stock units (RSUs), performance shares, performance units and other stock-based awards valued in whole or in part by reference to or otherwise based on the common stock or other securities, and non-equity incentive awards that are not valued by reference to or payable in shares, to our employees, officers and non-employee directors for the purpose of strengthening their commitment to the success of the Company and stimulating their efforts on behalf of the Company, as well as attracting and retained employees, officers and non-employee directors. The number of shares of common stock issuable pursuant to all awards granted under the 2011 Incentive Plan shall not exceed shares. No awards have been granted under the 2011 Incentive Plan to date. The number of shares issued or reserved pursuant to the 2011 Incentive Plan (or pursuant to outstanding awards) is subject to adjustment as a result of mergers, consolidations, reorganizations, stock splits, stock dividends and other changes in our common stock. If any shares subject to any award under the 2011 Incentive Plan are forfeited or payment is made in a form other than shares or the award otherwise terminates without payment being made, the shares subject to such awards generally may again be available for issuance under the 2011 Incentive Plan. However, shares withheld or surrendered in payment of the exercise price for stock options or withheld for taxes upon the exercise or settlement of an award will not be available for issuance under the 2011 Incentive Plan. Notwithstanding the foregoing, an unlimited number of shares may be issued under the 2011 Incentive Plan upon the assumption of, or in substitution for, outstanding awards previously granted by an entity in connection with a corporate transaction, unless otherwise expressly provided for under the 2011 Incentive Plan.

Administration. The 2011 Incentive Plan will be administered by either the full board of directors or a committee as designated by the board of directors (referred to herein as the committee). Except to the extent the board of directors reserves administrative powers to itself or appoints a different committee to administer the 2011 Incentive Plan, the committee will be the board of directors with respect to all non-employee director grantees and the compensation committee of the board of directors with respect to all executive officer grantees. Unless the board of directors or the compensation committee chooses to administer the 2011 Incentive Plan with respect to other non-executive officer grantees, a committee consisting of the CEO will do so, provided the CEO is a member of the board of directors. In addition, to the extent that the board of directors considers it desirable to comply with Rule 16b-3 of the Exchange Act or meet the performance-based exception to tax deductibility limitations under Internal Revenue Code Section 162(m), the committee will consist of two or more members of the board of directors, all of whom qualify both as outside directors within the meaning of Internal Revenue Code Section 162(m) and non-employee directors within the meaning of Rule 16b-3 of the Exchange Act. Subject to the terms of the 2011 Incentive Plan, the committee has full power and sole discretion to administer the 2011 Incentive Plan, including, among other things, to select when, to whom and in what types and amounts awards will be granted; to determine the terms and conditions of awards, including but not limited to the term, the vesting schedule, restrictions, and performance criteria relating to any award; to determine the settlement, cancellation, forfeiture, exchange or surrender of any award; to make adjustments in the terms and conditions of awards; to construe and interpret the 2011 Incentive Plan and any award agreement; to establish, amend and revoke rules and regulations for the administration of the 2011 Incentive Plan; to make all determinations deemed necessary or advisable for administration of the 2011 Incentive Plan; and to exercise any powers and perform any acts it deems necessary or advisable to administer the 2011 Incentive Plan.

Eligibility. Our employees, officers and non-employee directors are eligible to receive awards under the 2011 Incentive Plan, as determined by the committee.

Limits on Awards. The 2011 Incentive Plan contains several limits on the number of shares and the amount of cash that may be issued as awards.

To the extent the committee determines that compliance with the performance-based exception to tax deductibility limitations under Internal Revenue Code Section 162(m) is desirable, the maximum number of shares of common stock that may be subject to one or more awards to any individual pursuant to the 2011 Incentive Plan during any calendar year is 3,500,000 shares of common stock, and the maximum potential value of awards to be settled in cash or property (other than shares) that may be granted with respect to any calendar year shall not exceed $15,000,000 as to each individual.

Stock Options. The committee is authorized to grant stock options, including incentive stock options and non-qualified stock options. A stock option allows a grantee to purchase a specified number of shares at a predetermined exercise price during a fixed period measured from the date of grant. The exercise price per share of stock subject to a stock option is determined by the committee and cannot be less than 100% of the fair market value of a share on the grant date. Except in the case of a change in our capital structure, extraordinary distribution to stockholders, or other corporate transaction or event that affects our common stock, the committee shall not reprice an option without stockholder approval. The term of each option is fixed by the committee, provided that it may not exceed ten years from the grant date. Such awards may vest and become exercisable in whole or in part at such time or times as determined by the committee. Options may be exercised by payment of the purchase price in cash or stock as provided in the 2011 Incentive Plan, subject to approval of the committee.

Stock Appreciation Rights. The committee may grant stock appreciation rights, which entitle a grantee the right to receive upon exercise of the stock appreciation right an amount equal to the difference between base amount of the stock appreciation right and the fair market value of a share on the exercise date, multiplied by the number of shares with respect to which the stock appreciation right relates. The committee determines the terms and conditions of such awards, including the base amount of the stock appreciation right. Except in the case of a change in our capital structure, an extraordinary distribution to stockholders, or other corporate transaction or event that affects our common stock, the committee shall not reprice a stock appreciation right without stockholder approval.

Restricted Stock. The committee may award restricted stock consisting of shares that may not be transferred or disposed of by grantees until certain restrictions on such shares as established by the committee lapse. A grantee receiving restricted stock will have all of the rights of a stockholder, including the right to vote the shares and the right to receive any dividends on shares once they vest, unless the committee otherwise determines.

Restricted Stock Units. The committee may also make awards of restricted stock units, consisting of a right to receive shares at a future date upon the satisfaction of certain conditions set forth in the award agreement. Awards of restricted stock units are subject to such limitations as the committee may impose, which limitations may lapse at the end of a specified period, in installments or otherwise. Restricted stock unit awards carry no voting or dividend rights or other rights associated with stock ownership.

Performance Units. The committee may grant performance units, which entitle a grantee to cash or shares conditioned upon the fulfillment of certain performance conditions and other restrictions as specified by the committee. A performance unit is valued based upon a value established by the committee. The committee will determine the terms and conditions of such awards, including performance and other restrictions placed on these awards. Performance measures may be selected from among those listed in the 2011 Incentive Plan, as described below, or other specific criteria determined by the committee, in each case, over any period or periods determined by the committee.

Performance Shares. The committee may grant performance shares, which entitle a grantee to a certain number of shares of common stock, conditioned upon the fulfillment of certain performance conditions and other restrictions as specified by the committee. The committee will determine the terms and conditions of such awards, including performance and other restrictions placed on these awards. Performance measures may be selected from among those listed in the 2011 Incentive Plan, as described below, or other specific criteria determined by the committee, in each case, over any period or periods determined by the committee.

Non-Equity Incentive Awards. The committee may grant non-equity incentive awards, which awards are under the 2011 Incentive Plan that are not granted, valued by reference to, or payable in shares of common stock, alone or in conjunction with other awards. The committee will determine the terms and conditions of such awards, including performance and other restrictions placed on these awards. Performance measures may be selected from among those listed in the 2011 Incentive Plan, as described below, or other specific criteria determined by the committee, in each case, over any period or periods determined by the committee.

Other Stock-Based Awards. In order to enable us to respond to significant regulatory developments as well as to trends in executive compensation practices, the 2011 Incentive Plan authorizes the committee to grant awards that are valued in whole or in part by reference to or otherwise based on our securities. The committee shall determine the terms and conditions of such awards, including consideration paid for awards granted as share purchase rights and whether awards are paid in shares or cash.

Non-Employee Director Annual Grants. Generally, each member of our board of directors who is not our employee will be granted on each regularly scheduled annual meeting of stockholders or at such other time as the board of directors may, in its sole discretion, determine, restricted stock units, restricted stock or a combination thereof representing and/or shares having a fair market value on the grant date of up to $300,000. A person who first becomes a non- employee director after the conclusion of the annual meeting of stockholders and prior to August 1 of any year shall be granted the full director annual grant for such year as of December 15. A person who first becomes a non-employee director on or after August 1 of any year from and after 2012 and prior to the first annual meeting of stockholders following the date the person becomes a non-employee director shall be granted a prorated director annual grant for such first year as set forth in the 2011 Incentive Plan.

Non-employee directors may elect to defer receipt of payment of restricted stock units awarded in lieu of cash or shares, as applicable, with respect to director annual grants or director fees, until a time after the date that they would otherwise vest in accordance with the terms of the 2011 Incentive Plan.

Performance-Based Awards. The committee may require satisfaction of pre-established performance goals, consisting of one or more business criteria and a targeted performance level with respect to such criteria, as a condition of awards being granted or becoming exercisable or payable under the 2011 Incentive Plan, or as a condition to accelerating the timing of the grant or vesting of an award. The performance measure(s) to be used for purposes of any awards intended to satisfy the performance-based exception to the limitations of Internal Revenue Code Section 162(m) must be chosen from among the following: (i) earnings (either in the aggregate or on a per-share basis); (ii) net income; (iii) operating income; (iv) operating profit; (v) cash flow; (vi) stockholder returns (including return on assets, investments, equity, or gross sales) (including income applicable to common stockholders or other class of stockholders); (vii) return measures (including return on assets, equity, sales or capital expenditures); (viii) earnings before or after either, or any combination of, interest, taxes, depreciation or amortization (EBITDA); (ix) gross revenues; (x) share price (including growth measures and total stockholder return or attainment by the shares of a specified value for a specified period of time); (xi) reductions in expense levels in each case where applicable determined either in a Company-wide basis or in respect of any one or more business units; (xii) net economic value; (xiii) market share; (xiv) annual net income to common stock; (xv) earnings per share; (xvi) annual cash flow provided by operations; (xvii) changes in annual revenues; (xviii) strategic business criteria, consisting of one or more objectives based on meeting specified revenue, market penetration, geographic business expansion goals, objectively identified project milestones, production volume levels, cost targets, and goals relating to acquisitions or divestitures; (xix) reserve growth (reserve replacement) or reserves per share; (xx) reserve replacement efficiency ratio; (xxi) productions growth or production per share; (xxii) drilling results; (xxiii) development costs; (xxiv) economic value added; (xxv) sales; (xxvi) costs; (xxvii) results of customer satisfaction surveys; (xxviii) aggregate product price and other product price measures; (xxix) safety record; (xxx) service reliability; (xxxi) operating and maintenance cost management; (xxxii) energy production availability performance measures; (xxxiii) debt rating; and/or (xxxiv) achievement of objective business or operational goals such as market share and/or business development; provided that clauses (i) through (vii) may be measured on a pre- or post-tax basis; and provided further that the committee may, on the grant date of an award intended to comply with the performance-based exception to the limitations of Section 162(m), and in the case of other grants, at any time, provide that the formula for such award may include or exclude items to measure specific objectives, such as losses from discontinued operations, extraordinary gains or losses, the cumulative effect of accounting changes, acquisitions or divestitures, foreign exchange impacts and any unusual, nonrecurring gain or loss. For awards intended to comply with the performance-based exception to the limitations of Section 162(m), the committee shall set the performance measures within the time period prescribed by Section 162(m). The levels of performance required with respect to performance measures may be expressed in absolute or relative levels and may be based upon a set increase, set positive result, maintenance of the status quo, set decrease or set negative result, and may be measured annually, cumulatively over a period of years or over such other period determined by the committee. Performance measures may differ for awards to different grantees. The committee shall specify the weighting (which may be the same or different for multiple objectives) to be given to each performance measure for purposes of determining the final amount payable with respect to any such award. Any one or more of the performance measures may apply to the grantee, to a department, unit, division or function within the Company or any one or more of its affiliates, or to the Company and/or any one or more of its affiliates; and may apply either alone or relative to the performance of other businesses or individuals (including industry or general market indices). The committee has the discretion to adjust the determinations of the degree of attainment of the pre-established performance goals; provided, however, that awards which are designed to qualify for the performance-based exception to the limitations of Section 162(m) may not be adjusted upward (the committee retains the discretion to adjust such awards downward) so as to cause the performance based exception to be unavailable. The committee may not delegate any responsibility with respect to awards intended to qualify for the performance-based exception. All determinations by the committee as to the achievement of the performance measure(s) will be in writing prior to payment of the award.

Payment and Deferral of Awards. The committee may require or permit grantees to defer the distribution of all or part of an award in accordance with such terms and conditions as the committee may establish. The 2011 Incentive Plan is intended to constitute an unfunded plan for incentive and deferred compensation, provided, that the 2011 Incentive Plan authorizes the committee to place shares or other property in trusts or to make other arrangements to provide for payment of obligations under the 2011 Incentive Plan, which trusts or other arrangements shall be consistent with the unfunded status of the 2011 Incentive Plan, unless the committee otherwise determines. We may require as a condition to the payment of an award that the grantee satisfy applicable withholding taxes and may provide that a portion of the stock or other property to be distributed will be withheld to satisfy such tax obligations.

Transfer Limitations on Awards. Awards granted under the 2011 Incentive Plan generally may not be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered except by will or by the laws of descent and distribution. Each award will be exercisable during the grantee s lifetime only by the grantee or, if permitted under applicable law, by the grantee s guardian or legal representative. However, certain transfers of awards for estate incentive planning or wealth transfer incentive planning purposes may be permitted in the discretion of the committee in accordance with the 2011 Incentive Plan.

Amendment and Termination. The 2011 Incentive Plan may be amended, altered, suspended, discontinued, or terminated by the board of directors in whole or in part without further stockholder approval, unless such approval of an amendment or alteration is required by law or regulation or under the rules of the New York Stock Exchange (or any securities exchange or other form of securities market on which the common stock is then listed or quoted). The board of directors, in its discretion, may seek to obtain stockholder approval for amendments or other actions affecting the 2011 Incentive Plan for which stockholder approval is not required in any circumstance that the board of directors determines such approval would be advisable. In addition, except as otherwise specifically permitted in the 2011

Incentive Plan or any award agreement thereunder, no amendment, modification or termination of the 2011 Incentive Plan may adversely

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affect in any material way any award previously granted under the 2011 Incentive Plan, without the written consent of the grantee of such award, other than an amendment to the change in control provisions of the 2011 Incentive Plan prior to the time that a change in control of us may occur).

In no event may an award be granted pursuant to the 2011 Incentive Plan on or after the tenth anniversary of the date our board of directors approved the 2011 Incentive Plan.

Change in Control. If, upon or within two years after a change in control (as defined in the 2011 Incentive Plan), a grantee has a termination of affiliation with the Company and its affiliates (but not including a termination of service as a director), excluding any transfer to the Company or its affiliates, voluntarily for good reason or involuntarily (other than due to cause, death, disability, or retirement (each as defined in the 2011 Incentive Plan): (i) all of the grantee s outstanding awards will become fully vested, (ii) all performance criteria will be deemed achieved or fulfilled (at their target level, to the extent applicable), and (iii) the any nonqualified options subject to such accelerated vesting will continue to be exercisable after such termination of affiliation for 18 months (or if less, the remaining original option term).

Assumption of Certain Williams Equity Incentive Awards. In connection with and at the time of the spin-off, it is anticipated that we will assume equity-based incentive compensation awards granted by Williams to our employees as follows: (i) we will assume all Williams restricted stock units awards granted to our employees prior to the date of the spin-off (including time-based and performance-based restricted stock units) and convert such awards into restricted stock units with respect to our common stock with substantially the same terms and conditions as in effect prior to the spin-off, (ii) we will assume all outstanding Williams stock options granted to our employees after December 31, 2005 and prior to the date of the spin-off and convert such awards into options to acquire our common stock with substantially the same terms and conditions as in effect prior to the spin-off, (iii) we will assume all outstanding Williams stock options granted to our employees prior to December 31, 2005 and convert such awards into options to acquire a number of shares of our common stock and Williams common stock (in proportions reflecting the number of shares of our common stock issued in the spin-off in respect of each share of Williams common stock then outstanding) with substantially the same terms and conditions as in effect prior to the spin-off, in each case, with such equitable adjustments as reasonably necessary to prevent a dilution or enlargement of the employees rights thereunder (including equitable adjustments to the manner in which total stockholder return is calculated for purposes of performance-based restricted stock units).

Employee Stock Purchase Plan

The following is a summary of the material terms of the WPX Energy, Inc. 2011 Employee Stock Purchase Plan, which is referred to as the ESPP. The ESPP was adopted on , 2011 by our board of directors. This description is not complete. For more information, we refer you to the full text of the ESPP, which we filed as an exhibit to the registration statement of which this prospectus forms a part.

The ESPP provides our employees the opportunity to purchase our common stock through payroll deductions. The maximum number of shares that shall be made available for sale under the ESPP is shares. This number may be adjusted for stock splits and similar events. If the total number of shares that would otherwise be subject to rights to purchase at the beginning of an offering period exceeds the number of shares then available under the ESPP, the committee will make a pro rata allocation of the shares remaining available under the ESPP. In such event, the committee will give affected participants written notice of the number of shares of common stock allocated and will reduce the rate of payroll deductions as necessary.

Administration. The ESPP will be administered by either the board of directors or a committee as designated by our board of directors (referred to herein as the committee). Subject to the provisions of the ESPP, the committee will have full power and authority to promulgate rules and regulations as it deems necessary for the proper administration of the ESPP, to interpret the provisions and supervise the administration of the ESPP and to take all action in connection with or related to the ESPP as it deems necessary or advisable.

Eligibility. Employees are generally eligible to participate in the ESPP if they are (i) customarily employed by us or one of our designated subsidiaries and (ii) employed as of the first day of the offering period; but in all cases excluding any such employee who is a highly compensated employee within the meaning of Section 414(q) of the Code and who holds a position that has been classified as an executive position by our executive compensation department. However, such employees will not be eligible to participate in the ESPP if, immediately following the grant, they (or any other person whose stock would be attributed to them pursuant to Section 424(d) of the Code) would possess common stock and/or hold outstanding options to purchase stock, or stock of a subsidiary, representing 5% or more of the total combined voting power or value of all such classes of stock or of any subsidiary.

Offering Period. The ESPP generally provides for offerings beginning on the first day of the year or the first day of the seventh month of the year (the offering date) and concludes on the last day of the sixth month after the offering date (the purchase date). The six month period for which an offering is effective is referred to as an offering period . However, the first offering period under the ESPP is anticipated to be a shorter offering period beginning on a date following the completion of the spin-off to be designated by the committee and ending on June 30, 2012, or such later date designated by the committee. Eligible employees may elect to participate in an offering period. Such election shall provide the right to purchase shares of common stock on the purchase date of such offering period. The number of shares of common stock shall be determined by dividing each participant s payroll deductions accumulated during each offering period prior to such purchase date and retained in the participant s payroll deduction account as of such purchase date by the applicable purchase price. The right to purchase shares of common stock with respect to an offering period will expire on the purchase date.

In general, the maximum payroll deduction for the ESPP, to be applied annually, is $15,000, or such greater amount as designated by the committee. In general, the maximum payroll deductions that a participant may elect for any offering period shall not exceed $7,500.

Purchase of Stock; Limitations on Purchase of Stock. Unless a participant reduces his or her payroll deduction to zero, or otherwise becomes ineligible, the purchase of shares of common stock will be exercised automatically on each purchase date, and, subject to the limitations on the number of shares that may be purchased under the ESPP, the maximum number of shares will be purchased for such participant at the applicable purchase price with the accumulated payroll deductions elected to be withheld under the ESPP. Participants may not purchase shares of common stock under the ESPP to the extent that their rights to purchase shares under the ESPP, when combined with all other rights and options granted to them under all employee stock purchase ESPPs or any subsidiary corporation ESPPs, would permit them to purchase shares of common stock with a fair market value (determined on the first day of the applicable offering period) in excess of $25,000 for any calendar year in which such purchase right is outstanding at any time. In order to comply with this $25,000 limitation, we may decrease the rate of payroll deductions to zero percent at any time during the offering period.

Purchase Price. The purchase price per share of common stock under the ESPP will be the lesser of: (i) 85% of the fair market value of a share of common stock on the offering date and (ii) 85% of the fair market value of a share of common stock on the purchase date.

Termination of Employment. Upon termination of a participant s employment during the offering period for any reason, including voluntary termination, retirement or death, the payroll deductions credited to the ESPP (that have not been used to purchase shares of common stock) will be returned to him or her or, in the case of his or her death, to the person or persons entitled thereto. The participant s option will be automatically terminated. Such termination will be deemed a withdrawal from the ESPP.

Transferability. Rights under the ESPP are not transferable by participants, other than by will or the laws of descent and distribution or as otherwise allowed by the ESPP by way of designation of a beneficiary. Any such attempt at assignment, transfer, pledge or other disposition will have no effect, except that we may treat such act as an election to withdraw funds.

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Amendment; Termination. The board may at any time and for any reason terminate or amend the ESPP. Except as allowed by the ESPP generally with respect to changes in capitalization or corporate transactions, no such termination of the ESPP may affect options previously granted. Additionally, except as allowed by the ESPP generally with respect to changes in capitalization or corporate transactions, no such amendment to the ESPP shall make any change in any option previously granted that adversely affects the rights of any participant. We will obtain stockholder approval of any amendment in such a manner and to such a degree as required to the extent necessary to comply with Section 423 of the Code or any other applicable law, regulation or stock exchange rule.

Executive Compensation and Other Information

2010 Summary Compensation Table

The following table sets forth certain information with respect to the compensation of the NEOs earned during fiscal years 2010, 2009 and 2008.

and Principal on(1)	Year	Salary(2)	Bonus	Stock Awards(3)	Option Awards(4)	Non-Equity Incentive Plan Compensation(5)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(6)	All Other Compensation(7)	Tota
J. Malcolm r Chairman,	2010	$ 1,100,000	$	$ 2,936,283	$ 1,902,806	$ 1,276,378	$ 744,426	$ 43,805	$ 8,00
ent & Executive	2009	1,142,308		2,116,863	2,846,407	1,903,360	1,399,796	71,100	9,47
r liams	2008	1,094,231		2,906,309	2,789,127	2,000,000	1,201,514	56,134	10,04
l R. Chappel Financial	2010	610,154		1,436,882	407,743	559,052	225,539	16,320	3,25
r	2009	623,077		1,242,734	618,783	765,047	383,380	16,320	3,64
liams	2008	597,115		2,114,349	651,405	780,008	330,531	15,744	4,48
A. Hill	2010	493,208		1,257,287	356,777	384,479	315,626	16,304	2,82
Vice President ation & ction of	2009	503,654		1,056,319	525,969	566,473	427,867	37,786	3,11
ns	2008	480,962		1,606,867	495,071	579,633	363,151	30,371	3,55
J. Bender	2010	477,954		933,975	265,033	359,122	188,427	33,900	2,25
	2009	488,077		807,773	402,209	522,119	250,679	26,647	2,49

Vice President eneral el of Williams	2008	466,538	1,271,209	390,840	533,132	216,799	30,323	2,90
L. Ewing Vice President	2010	442,692	933,975	265,033	328,364	233,254	35,579	2,23
hief istrative	2009	446,538	745,640	371,269	485,362	304,374	31,093	2,38
r of ms	2008	370,198	299,757	118,485	435,072	248,784	30,096	1,50

(1) **Name and Principal Position.** On January 3, 2011 Mr. Malcolm retired as Chairman, President and Chief Executive Officer of Williams.

(2) **Salary**. All NEOs did not receive a salary increase in 2009. The increase in the reported 2009 salary was due to a payroll timing issue resulting in a 27th bi-weekly paycheck being issued in the calendar year.

(3) **Stock Awards.** Awards were granted under the terms of Williams 2007 Incentive Plan and include time-based and performance-based RSUs. Amounts shown are the grant date fair value of awards computed in accordance with FASB ASC Topic 718. The assumptions used to value the stock awards can be found in Williams Annual Report on Form 10-K for the year-ended December 31, 2010.

The potential maximum values of the performance-based RSUs, subject to changes in performance outcomes, are as follows:

	2010 Performance-Based RSU Maximum potential
Steven J. Malcolm	$ 5,872,566
Donald R. Chappel	1,468,141
Ralph A. Hill	1,284,639
James J. Bender	954,294
Robyn L. Ewing	954,294

(4) **Option Awards.** Awards are granted under the terms of Williams 2007 Incentive Plan and include non-qualified stock options. Amounts shown are the grant date fair value of awards computed in accordance

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with FASB ASC Topic 718. The assumptions used to value the option awards can be found in our Annual Report on Form 10-K for the year-ended December 31, 2010.

(5) **Non-Equity Incentive Plan**. Under Williams AIP, the maximum annual incentive pool funding for NEOs is 250% of target. The reserve provision of the AIP was eliminated in 2009 and the outstanding balances for the NEOs remained at risk over a three year performance period in which threshold performance levels must be attained in order for the balances to be paid and will be reduced if threshold is not met in accordance with previous plan provisions. Threshold performance was met in 2009 and 2010 and a portion of the respective reserve balance was paid to each NEO each year.

The annual cash incentive and reserve amounts paid in 2011 as it relates to 2010 performance are as follows:

	Reserve Balance	AIP for 2010	Amount of Reserve Paid in 2011	Total AIP plus Reserve for 2010
Steven J. Malcolm	$ 242,756	$ 1,155,000	$ 121,378	$ 1,276,378
Donald R. Chappel	60,103	529,000	30,052	559,052
Ralph A. Hill	72,958	348,000	36,479	384,479
James J. Bender	44,244	337,000	22,122	359,122
Robyn L. Ewing	20,728	318,000	10,364	328,364

(6) **Change in Pension Value and Nonqualified Deferred Compensation Earnings.** The amount shown is the aggregate change from December 31, 2009 to December 31, 2010 in the actuarial present value of the accrued benefit under the qualified pension and supplemental plan sponsored by Williams. Please refer to the Pension Benefits table for further details of the present value of the accrued benefit. The underlying benefit programs have been consistent during the time period displayed. The primary reason for the fluctuation in the change in present value during this time is due to the use of updated discount rates and conversion rates.

(7) **All Other Compensation.** Amounts shown represent payments by Williams made on behalf of the NEOs and includes life insurance premium, a 401(k) matching contribution and perquisites (if applicable). Perquisites include financial planning services, mandated annual physical exam, home security monitoring for the CEO and personal use of Williams company aircraft. The incremental cost method was used to calculate the personal use of the Company aircraft. The incremental cost calculation includes such items as fuel, maintenance, weather and airport services, pilot meals, pilot overnight expenses, aircraft telephone and catering. The amounts of perquisites for Mr. Malcolm, Mr. Bender and Ms. Ewing are included because the aggregate amounts exceed $10,000.

	Financial Planning	Annual Physical Exam	Home Security	Company Aircraft Personal Usage
Steven J. Malcolm	$ 15,000	$ 0	$ 438	$ 12,047
James J. Bender	15,000	2,646	0	0
Robyn L. Ewing	15,000	4,437	0	0

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2010 Grants of Williams   Plan Based Awards

The following table sets forth certain information with respect to the grant of stock options to acquire Williams   stock, RSUs with respect to Williams   stock and awards payable under Williams   annual cash incentive program during the fiscal year 2010 to the NEOs.

Grant Date	Equity Future Payouts Under Non-Equity Incentive Plan Awards(1) Threshold	Target	Maximum	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold	Target(2)	Maximum	All Other Stock Awards: Number of Shares of Stock or Units(3)	All Other Option Awards Number of Securities Underlying Options(4)	Exercise or Base Price of Option Awards	G Da V St C A
2/23/2010	$ 121,378	$ 1,221,378	$ 2,871,378					271,055	$ 21.22	$ 1
2/23/2010					140,492	280,984				2
2/23/2010	30,052	487,667	1,174,090					58,083	21.22	
2/23/2010					35,123	70,246				
2/23/2010							35,123			
2/23/2010	36,479	357,064	837,941					50,823	21.22	
2/23/2010					30,733	61,466				
2/23/2010							30,733			
2/23/2010	22,122	332,792	798,797					37,754	21.22	
2/23/2010					22,830	45,660				
2/23/2010							22,830			
2/23/2010	10,364	298,114	729,739					37,754	21.22	
2/23/2010					22,830	45,660				
2/23/2010							22,830			

(1) Non-Equity Incentive Awards. Awards from Williams   2010 AIP are shown.

Threshold: Because one-half of the AIP reserve balance from prior years is payable in 2011 upon meeting threshold performance, one-half of the reserve balance is shown.

Target: The amount shown is based upon an EVA® attainment of 100%, plus one-half of the existing AIP reserve balance.

Maximum: The maximum amount the NEOs can receive is 250% of their AIP target, plus one-half of the AIP reserve balance.

(2) Represents performance-based RSUs granted under Williams 2007 Incentive Plan. Performance-based RSUs can be earned over a three-year period only if the established performance target is met and the NEO is employed on the certification date, subject to certain exceptions such as the executive s death or disability. These shares will be distributed no earlier than the third anniversary of the grant other than due to a termination upon a change in control. If performance plan goals are exceeded, the NEO can receive up to 200% of target. If plan goals are not met, the NEO can receive as little as 0% of target.

(3) Represents time-based RSUs granted under Williams 2007 Incentive Plan. Time-based units vest three years from the grant date of 2/23/2010 on 2/23/2013.

(4) Represents stock options granted under Williams 2007 Incentive Plan. Stock options granted in 2010 become exercisable in three equal annual installments beginning one year after the grant date. One-third of the options vested on 2/23/2011. Another one-third will vest on 2/23/2012, with the final one-third vesting on 2/23/2013. Once vested, stock options are exercisable for a period of 10 years from the grant date.

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2010 Outstanding Williams Equity Awards

The following table sets forth certain information with respect to the outstanding Williams equity awards held by the NEOs at the end of fiscal year 2010.

	Option Award						Stock Awards				
	Grant Date(1)	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options	Option Exercise Price	Expiration Date	Grant Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested	Equity Incentive Plan Awards: Number of Unearned Shares, Units of Stock or Other Rights That Have Not Vested	Equ Incen Pla Awa Mar or Payo Valu of Unear Shar Uni or Oth Righ Tha Hav No Veste
J.											
m	2/23/2010		271,055		$ 21.22	2/23/2020	2/23/2010(3)		140,492	$ 3,472,962	
	2/23/2009	169,429	338,858		10.86	2/23/2019	2/23/2009(3)		288,401	7,129,273	
	2/25/2008	144,927	72,464		36.50	2/25/2018	2/25/2008(3)		82,192	2,031,786	
	2/26/2007	200,000			28.30	2/26/2017					
	3/3/2006	250,000			21.67	3/3/2016					
	2/25/2005	225,000			19.29	2/25/2015					
	2/5/2004	300,000			9.93	2/5/2014					
	2/11/2002	200,000			15.86	2/11/2012					
	9/19/2001	33,333			26.79	9/19/2011					
	4/2/2001	27,232			39.98	4/2/2011					
	1/18/2001	114,373			34.77	1/18/2011					
.											
el	2/23/2010		58,083		21.22	2/23/2020	2/23/2010(2)		35,123	868,241	
	2/23/2009	36,832	73,665		10.86	2/23/2019	2/23/2010(3)		35,123	868,241	
	2/25/2008	33,848	16,924		36.50	2/25/2018	2/23/2009(2)		73,145	1,808,144	
	2/26/2007	48,450			28.30	2/26/2017	2/23/2009(3)		73,145	1,808,144	

	3/3/2006	41,921		21.67	3/3/2016	2/25/2008(2)	19,911	492,200
	2/25/2005	55,000		19.29	2/25/2015	2/25/2008(3)	39,822	984,400
	2/5/2004	75,000		9.93	2/5/2014			
	4/16/2003	175,000		5.10	4/16/2013			
A.								
	2/23/2010		50,823	21.22	2/23/2020	2/23/2010(2)	30,733	759,720
	2/23/2009	31,307	62,616	10.86	2/23/2019	2/23/2010(3)	30,733	759,720
	2/25/2008	25,724	12,863	36.50	2/25/2018	2/23/2009(2)	62,173	1,536,917
	2/26/2007	43,605		28.30	2/26/2017	2/23/2009(3)	62,173	1,536,917
	3/3/2006	30,488		21.67	3/3/2016	2/25/2008(2)	15,132	374,063
	2/25/2005	40,000		19.29	2/25/2015	2/25/2008(3)	30,264	748,126
	1/18/2001	22,875		34.77	1/18/2011			
J.								
	2/23/2010		37,754	21.22	2/23/2020	2/23/2010(2)	22,830	564,358
	2/23/2009	23,941	47,882	10.86	2/23/2019	2/23/2010(3)	22,830	564,358
	2/25/2008	20,308	10,155	36.50	2/25/2018	2/23/2009(2)	47,544	1,175,288
	2/26/2007	29,070		28.30	2/26/2017	2/23/2009(3)	47,544	1,175,288
	3/3/2006	24,136		21.67	3/3/2016	2/25/2008(2)	11,946	295,305
	2/25/2005	40,000		19.29	2/25/2015	2/25/2008(3)	23,893	590,635
	2/5/2004	15,000		9.93	2/5/2014			
L.								
	2/23/2010		37,754	21.22	2/23/2020	2/23/2010(2)	22,830	564,358
	2/23/2009	22,099	44,199	10.86	2/23/2019	2/23/2010(3)	22,830	564,358
	2/25/2008	6,156	3,079	36.50	2/25/2018	2/23/2009(2)	43,887	1,084,887
	2/26/2007	10,174		28.30	2/26/2017	2/23/2009(3)	43,887	1,084,887
	3/3/2006	11,738		21.67	3/3/2016	2/25/2008(2)	3,622	89,536
	2/25/2005	23,000		19.29	2/25/2015	2/25/2008(3)	4,829	119,373

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Stock Options

(1) The following table reflects the vesting schedules for associated stock option grant dates for awards that had not been 100% vested as of December 31, 2010.

Grant Date	Vesting Schedule	Vesting Dates
2/23/2010	One-third vests each year for three years	2/23/2011, 2/23/2012, 2/23/2013
2/23/2009	One-third vests each year for three years	2/23/2010, 2/23/2011, 2/23/2012
2/25/2008	One-third vests each year for three years	2/25/2009, 2/25/2010, 2/25/2011

Stock Awards

(2) The following table reflects the vesting dates for associated time-based restricted stock unit award grant dates.

Grant Date	Vesting Schedule	Vesting Dates
2/23/2010	100% vests in three years	2/23/2013
2/23/2009	100% vests in three years	2/23/2012
2/25/2008	100% vests in three years	2/25/2011

(3) All performance-based RSUs are subject to attainment of performance targets established by the Committee. These awards will vest no earlier than the end of the performance period and therefore do not have a specific vesting date. The awards included on the table are outstanding as of December 31, 2010.

(4) Values are based on a closing stock price for Williams of $24.72 on December 31, 2010.

2010 Williams Option Exercises and Stock Vested

The following table sets forth certain information with respect to options to acquire the stock of Williams exercised by the NEO and stock that vested during fiscal year 2010.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting
Steven J. Malcolm	475,000	$ 10,096,083		$
Donald R. Chappel			19,069	410,746
Ralph A. Hill			17,162	369,669
James J. Bender			11,442	246,461
Robyn L. Ewing			4,005	86,268

The Committee determines pay based on a target total compensation amount. While the Committee reviews tally sheets and wealth accumulation information on each NEO, thus far amounts realized from previous equity grants have not been a material factor when the Committee determines pay. How much compensation the NEOs actually receive is significantly impacted by the stock market performance of Williams shares.

Retirement Plan

The retirement plan for Williams executives consists of two plans: the pension plan and the retirement restoration plan as described below. Together these plans provide the same level of benefits to our executives as the pension plan provides to all other employees of Williams. The retirement restoration plan was implemented to address the annual compensation limit of the Code.

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Pension Plan

Williams executives who have completed one year of service participate in Williams pension plan on the same terms as other Williams employees. The pension plan is a noncontributory, tax qualified defined benefit plan (with a cash balance design) subject to the Employee Retirement Income Security Act of 1974, as amended.

Each year, participants earn compensation credits that are posted to their cash balance account. The annual compensation credits are equal to the sum of a percentage of eligible pay (base pay and certain bonuses) and a percentage of eligible pay greater than the social security wage base. The percentage credited is based upon the participant s age as shown in the following table.

Age	Percentage of Eligible Pay		Percent of Eligible Pay Greater than the Social Security Wage Base
Less than 30	4.5%	+	from 1% to 1.2%
30-39	6%	+	2%
40-49	8%	+	3%
50 or over	10%	+	5%

For participants who were active employees and participants under the plan on March 31, 1998, and April 1, 1998, the percentage of eligible pay is increased by 0.3% multiplied by the participant s total years of benefit service earned as of March 31, 1998.

In addition, interest is credited to account balances quarterly at a rate determined annually in accordance with the terms of the plan.

The monthly annuity available to those who take normal retirement is based on the participant s account balance as of the date of retirement. Normal retirement age is 65. Early retirement eligibility begins at 55. At retirement, participants may choose to receive a single-life annuity (for single participants) or a qualified joint and survivor annuity (for married participants) or they may choose one of several other forms of payment having an actuarial value equal to that of the relevant annuity.

Retirement Restoration Plan

The Code limits pension benefits based on the annual compensation limit that can be accrued in tax-qualified defined benefit plans, such as Williams pension plan. Any reduction in an executive s pension benefit accrual due to these limits will be compensated, subject to a cap, under an unfunded top hat plan Williams retirement restoration plan.

The elements of compensation that are included in applying the payment and benefit formula for the retirement restoration plan are the same elements that are used, except for application of a cap, in the base pension plan for all Williams employees. The elements of pay included in that definition are total base pay, including any overtime, base pay-reduction amounts and cash bonus awards, if paid (unless specifically excluded under a written bonus or incentive-pay arrangement). Specifically excluded from the definition are severance pay, cost-of-living pay, housing pay, relocation pay (including mortgage interest differential), taxable and non-taxable fringe benefits and all other extraordinary pay, including any amounts received from equity compensation awards.

With respect to bonuses, annual cash incentives are considered in determining eligible pay under the pension plan. Long-term equity compensation incentives are not considered.

2010 Williams Pension Benefits

The following table sets forth certain information with respect to the actuarial present value of the accrued benefit as of December 31, 2010 under Williams qualified pension plan and retirement restoration plan.

Name	Plan Name	Number of Years Credited Services	Present Value of Accrued Benefit(1)	Payments During Last Fiscal Year
Steven J. Malcolm(2)(3)	Pension Plan	27	$ 829,307	
	Retirement Restoration Plan	27	5,497,857	
Donald R. Chappel(2)	Pension Plan	8	245,359	
	Retirement Restoration Plan	8	1,319,741	
Ralph A. Hill(3)	Pension Plan	27	586,869	
	Retirement Restoration Plan	27	1,321,013	
James J. Bender	Pension Plan	8	216,010	
	Retirement Restoration Plan	8	799,037	
Robyn L. Ewing(2)	Pension Plan	30	598,781	
	Retirement Restoration Plan	30	723,095	

(1) The primary actuarial assumptions used to determine the present values include an annual interest credit to normal retirement age equal to 5% and a discount rate equal to 5.29% for the pension plan and discount rate equal to 5.1% for the retirement restoration plan.

(2) Mr. Malcolm, Mr. Chappel and Ms. Ewing are the only NEOs eligible to retire as of December 31, 2010.

(3) Williams pension plan includes a Rule of 55 benefit that is a transition benefit that was provided to all employees meeting the eligibility criteria at the time Williams pension plan was converted from a final average pay formula to a cash balance formula. To be eligible for the Rule of 55 enhancement an employee s age and years of service at the time of the cash balance conversion in 1998 must have totaled 55. Mr. Malcolm and Mr. Hill are the only NEOs that met the eligibility criteria for the Rule of 55 transitional benefit.

Nonqualified Deferred Compensation

Williams does not provide nonqualified deferred compensation for any NEOs or other employees.

Change in Control Agreements

Williams has entered into change in control agreements with certain officers, including each of the NEOs, to facilitate continuity of management if there is a change in control of Williams. These arrangements do not provide for the payment of any benefits in the event of a future change in control of the ownership of WPX Energy. The provisions of such agreements are described below. The definitions of words in quotations are also provided below.

If during the term of a change in control agreement, a change in control occurs and (i) the employment of any NEO is terminated other than for cause, disability, death or a disqualification disaggregation or (ii) an NEO resigns for good reason, such NEO is entitled to the following:

Within 10 business days after the termination date:

Accrued but unpaid base salary, accrued earned but unpaid cash incentive, accrued but unpaid paid time off and any other amounts or benefits due but not paid (lump sum payment);

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On the first business day following six months after the termination date:

Prorated annual bonus for the year of separation through the termination date (lump sum payment);

A severance amount equal to three times his/her base salary for the NEO as of the termination date plus an annual bonus amount equal to his/her target percentage multiplied by his/her base salary in effect at the termination date as if performance goals were achieved at 100% (lump sum payment);

An amount equal to three times for the total allocations made by Williams for the NEOs in the preceding calendar year under our retirement restoration plan (lump sum payment);

An amount equal to the sum of the value of the unvested portion of the NEO s accounts or accrued benefits under Williams 401(k) plan that would have otherwise been forfeited (lump sum payment);

Continued participation in Williams medical benefit plans for so long as the NEO elects coverage or 18 months from the termination, whichever is less, in the same manner and at the same cost as similarly situated active employees;

All restrictions on stock options held by the NEO will lapse, and the options will vest and become immediately exercisable;

All restricted stock will vest and will be paid out only in accordance with the terms of the respective award agreements;

Continued participation in Williams directors and officers liability insurance for six years or any longer known applicable statute of limitations period;

Indemnification as set forth under Williams bylaws; and

Outplacement benefits for six months at a cost not exceeding $25,000.

In addition, each NEO is generally entitled to receive a gross-up payment in an amount sufficient to make him/her whole for any federal excise tax on excess parachute payments imposed under Section 280G and 4999 of the Code or any similar tax under any state, local, foreign or other law (other than Section 409A of the Code). However, in reviewing the change in control agreements in 2010 and 2011, the Committee approved eliminating this excise tax gross-up provision. The Committee opted to provide a best net provision providing the NEOs with the better of their after-tax benefit capped at the safe harbor amount or their benefit paid in full subjecting them to possible excise tax payments. Therefore, in 2011 Williams will provide the one year notice required by the NEOs change in control agreements in order to effect the change in 2012. After this change is implemented, Williams will no longer provide additional compensation to address excise taxes.

If an NEO s employment is terminated for cause during the period beginning upon a change of control and continuing for two years or until the termination of the agreement, whichever happens first, the NEO is entitled to accrued but unpaid base salary, accrued earned but unpaid cash incentive, accrued but unpaid paid time off and any other amounts or benefits due but not paid (lump sum payment).

The agreements with our NEOs use the following definitions:

Cause means an NEO s

conviction of or a plea of nolo contendere to a felony or a crime involving fraud, dishonesty or moral turpitude;

willful or reckless material misconduct in the performance of his/her duties that has an adverse effect on Williams or any of its subsidiaries or affiliates;

willful or reckless violation or disregard of the code of business conduct of Williams or the policies of Williams or its subsidiaries; or

habitual or gross neglect of his/her duties.

Cause generally does not include bad judgment or negligence (other than habitual neglect or gross negligence); acts or omissions made in good faith after reasonable investigation by the NEO or acts or omissions with respect to which Williams board of directors could determine that the NEO had satisfied the standards of conduct for indemnification or reimbursement under Williams bylaws, indemnification agreement or applicable law; or failure (despite good faith efforts) to meet performance goals, objectives or measures for a period beginning upon a change of control and continuing for two years or until the termination of the agreement, whichever happens first. An NEO s act or failure to act (except as relates to a conviction or plea of nolo contendere described above), when done in good faith and with a reasonable belief after reasonable investigation that such action or non-action was in the best interest of Williams or its affiliate or required by law shall not be Cause if the NEO cures the action or non-action within 10 days of notice. Furthermore, no act or failure to act will be Cause if the NEO acted under the advice of Williams counsel or required by the legal process.

Change in control means:

- Any person or group (other than an affiliate of Williams or an employee benefit plan sponsored by Williams or its affiliates) becomes a beneficial owner, as such term is defined under the Exchange Act, of 20% or more of the common stock of Williams or 20% or more of the combined voting power of all securities entitled to vote generally in the election of directors of Williams (Voting Securities), unless such person owned both more than 75% of common stock and Voting Securities, directly or indirectly, in substantially the same proportion immediately before such acquisition;

- Williams directors as of a date of the agreement (Existing Directors) and directors approved after that date by at least two-thirds of the Existing Directors cease to constitute a majority of the directors of Williams;

- Consummation of any merger, reorganization, recapitalization consolidation or similar transaction (Reorganization Transaction), other than a Reorganization Transaction that results in the person who was the direct or indirect owner of outstanding common stock and Voting Securities of Williams prior to the transaction becoming, immediately after the transaction, the owner of at least 65% of the then outstanding common stock and Voting Securities representing 65% of the combined voting power of the then outstanding Voting Securities of the surviving corporation in substantially the same respective proportion as that person s ownership immediately before such Reorganization Transaction; or

- approval by the stockholders of Williams of the sale or other disposition of all or substantially all of the consolidated assets of Williams or the complete liquidation of Williams other than a transaction that would result in (i) a related party owning more than 50% of the assets that were owned by Williams immediately prior to the transaction or (ii) the persons who were the direct or indirect owners of outstanding Williams common stock and Voting Securities prior to the transaction continuing to own, directly or indirectly, 50% or more of the assets that were owned by Williams immediately prior to the transaction.

A change in control will not occur if:

- the NEO agrees in writing prior to an event that such an event will not be a change in control; or

- Williams board of directors determines that a liquidation, sale or other disposition approved by the stockholders, as described in the fourth bullet above, will not occur, except to the extent termination occurred prior to such determination.

Disability means a physical or mental infirmity that impairs the NEO s ability to substantially perform his/her duties for twelve months or more and for which he/she is receiving income replacement benefits from a Williams plan for not less than three months.

Disqualification disaggregation means:

- the termination of an NEO s employment from Williams or an affiliate before a change in control for any reason; or

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the termination of an NEO s employment by a successor (during the period beginning upon a change of control and continuing for two years or until the termination of the agreement, whichever happens first), if the NEO is employed in substantially the same position and the successor has assumed the Williams change in control agreement.

Good reason means, generally, a material adverse change in the NEO s title, position or responsibilities, a reduction in the NEO s base salary, a reduction in the NEO s annual bonus, required relocation, a material reduction in the level of aggregate compensation or benefits not applicable to Williams peers, a successor company s failure to honor the agreement or the failure of Williams board of directors to provide written notice of the act or omission constituting cause.

Termination Scenarios

The following table sets forth circumstances that provide for payments by Williams to the NEOs following or in connection with a change in control of Williams or an NEO s termination of employment for cause, upon retirement, upon death and disability or not for cause, all while employed by Williams. NEOs are generally eligible to retire at the earlier of age 55 and completion of 3 years of service or age 65.

All values are based on a hypothetical termination date of December 31, 2010 and a closing stock price for Williams common stock of $24.72 on such date. The values shown are intended to provide reasonable estimates of the potential benefits the NEOs would receive upon termination. The values are based on various assumptions and may not represent the actual amount an NEO would receive. In addition to the amounts disclosed in the following table, a departing NEO would retain the amounts he/she has earned over the course of his/her employment prior to the termination event, including accrued retirement benefits and previously vested stock options and RSUs.

Name	**Payment**	**For Cause(1)**	**Retirement(2)**	**Death & Disability(3)**	**Not for Cause(4)**	**CIC(5)**
Malcolm, Steven J	AIP Reserve		$ 242,756	$ 242,756	$ 242,756	$ 242,756
	Stock options		5,645,264	5,645,264		5,645,264
	Stock awards		7,240,399	7,240,399	7,240,399	12,634,022
	Cash Severance					6,600,000
	Outplacement					25,000
	Health & Welfare					18,170
	Retirement Restoration Plan					2,207,808
	Enhancement					
	Tax Gross Up					8,649,197
	Total		**$ 13,128,419**	**$ 13,128,419**	**$ 7,483,155**	**$ 36,022,217**
Chappel, Donald R	AIP Reserve		$ 60,103	$ 60,103	$ 60,103	$ 60,103
	Stock options		1,224,287	1,224,287		1,224,287
	Stock awards		4,086,877	5,444,451	5,444,451	6,829,365

Cash Severance				3,213,000
Outplacement				25,000
Health & Welfare				26,699
Retirement Restoration Plan Enhancement				646,557
Tax Gross Up				2,966,960
Total	**$ 5,371,267**	**$ 6,728,841**	**$ 5,504,554**	**$ 14,991,971**

Name	Payment	For Cause(1)	Retirement(2)	Death & Disability(3)	Not for Cause(4)	CIC(5)
Hill, Ralph A	AIP Reserve		$ 72,958	$ 72,958	$ 72,958	$ 72,958
	Stock options		1,045,738	1,045,738		1,045,738
	Stock awards		3,360,366	4,527,523	4,527,523	5,715,453
	Cash Severance					2,448,765
	Outplacement					25,000
	Health & Welfare					26,346
	Retirement Restoration Plan Enhancement					636,018
	Tax Gross Up					
	Total		**$ 4,479,062**	**$ 5,646,219**	**$ 4,600,481**	**$ 9,970,278**
Bender, James J	AIP Reserve		$ 44,244	$ 44,244	$ 44,244	$ 44,244
	Stock options		795,784	795,784		795,784
	Stock awards		2,586,716	3,467,769	3,467,769	4,365,230
	Cash Severance					2,373,030
	Outplacement					25,000
	Health & Welfare					26,346
	Retirement Restoration Plan Enhancement					423,896
	Tax Gross Up					2,217,566
	Total		**$ 3,426,744**	**$ 4,307,797**	**$ 3,512,013**	**$ 10,271,096**
Ewing, Robyn L	AIP Reserve		$ 20,728	$ 20,728	$ 20,728	$ 20,728
	Stock options		744,737	744,737		744,737
	Stock awards		1,836,807	2,671,273	2,671,273	3,507,393
	Cash Severance					2,202,750
	Outplacement					25,000
	Health & Welfare					26,346
	Retirement Restoration Plan Enhancement					437,948
	Tax Gross Up					1,861,484
	Total		**$ 2,602,272**	**$ 3,436,738**	**$ 2,692,001**	**$ 8,826,386**

(1) If an NEO is terminated for cause or leaves Williams voluntarily, no additional benefits will be received.

(2)

If an NEO retires from Williams, then all unvested stock options will fully accelerate. A pro-rated portion of the unvested time based RSUs will accelerate and a pro-rated portion of any performance-based RSUs will vest on the original vesting date if the Committee certifies that the performance measures were met.

(3) If an NEO dies or becomes disabled, then all unvested stock options will fully accelerate. All unvested time-based RSUs will fully accelerate, and a pro-rated portion of any performance-based RSUs will vest if the Committee certifies that the performance measures were met.

(4) For an NEO who is involuntarily terminated who receives severance or for an NEO whose job is outsourced with no comparable internal offer, all unvested time-based RSUs will fully accelerate and a pro-rated portion of any performance-based RSUs will vest if the Committee certifies that the performance measures were met. However all unvested stock options cancel.

(5) See Change In Control Agreements above.

Please note that we make no assumptions as to the achievement of performance goals as it relates to the performance based RSUs. If an award is covered by Section 409A of the Code, lump sum payments and distributions occurring from these events will occur six months after the triggering event as required by the Code and our award agreements.

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PRINCIPAL STOCKHOLDER

All outstanding shares of our common stock are owned beneficially and of record by Williams. The following table sets forth information with respect to the beneficial ownership of our common stock immediately after the completion of this offering by:

- each person who is an executive officer;
- each person who is a director or is expected to serve as a director upon completion of this offering;
- all directors or persons expected to serve as directors and all executive officers as a group; and
- Williams, which, after completion of this offering will own % of the outstanding shares of our common stock, or % if the underwriters exercise their option to purchase additional common shares in full.

Beneficial ownership has been determined in accordance with the rules of the SEC and includes the power to vote or direct the voting of securities, or to dispose or direct the disposition thereof, or the right to acquire such powers within 60 days. Except as otherwise indicated, the persons or entities listed below have sole voting and investment power with respect to all shares of our common stock beneficially owned by them. The address for Williams is One Williams Center, Tulsa, Oklahoma 74172-0172. Unless otherwise indicated, the address for each director and executive officer listed is: c/o WPX Energy, Inc., One Williams Center, Tulsa, Oklahoma 74172-0172.

Name of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
The Williams Companies, Inc.(1)		%
Alan S. Armstrong	*	*
Ralph A. Hill	*	*
Donald R. Chappel	*	*
Ted T. Timmermans	*	*
James J. Bender	*	*
Robyn L. Ewing	*	*
Rodney J. Sailor	*	*
George A. Lorch	*	*
William G. Lowrie	*	*
All executive officers and directors as a group (nine persons)	*	*

* Represents less than 1%.

(1) Assumes the underwriters do not exercise their option to purchase additional common shares.

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ARRANGEMENTS BETWEEN WILLIAMS AND OUR COMPANY

This section provides a summary description of agreements between Williams and us relating to our restructuring transactions, this offering and our relationship with Williams after this offering. When used in this section, distribution date refers to the date, if any, following the offering on which Williams will distribute, or spin-off, its shares of our common stock to its stockholders.

This description of the agreements between Williams and us is a summary and, with respect to each such agreement, is qualified by reference to the terms of the agreement, each of which will be filed as an exhibit to the registration statement of which this prospectus is a part. We encourage you to read the full text of these agreements. We will enter into these agreements with Williams prior to the completion of this offering; accordingly, we will enter into these agreements with Williams in the context of our relationship as a wholly-owned subsidiary of Williams. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties.

Separation and Distribution Agreement

We will enter into a separation and distribution agreement with Williams that will set forth our agreements with Williams regarding the principal corporate transactions required to effect our restructuring transactions, this offering and the distribution of our shares to Williams common stockholders. It will also set forth the other agreements governing our relationship with Williams that we describe in this section.

Transfer of Assets and Assumption of Liabilities. The separation and distribution agreement will govern the assets to be contributed and transferred, and liabilities to be assumed, in connection with our separation from Williams so that each of Williams and us ultimately retains the assets of, and the liabilities associated with, our respective businesses.

In connection with the separation, all agreements, arrangements, commitments and understandings, including all intercompany loans and accounts payable and receivable, between us and our subsidiaries and other affiliates, on the one hand, and Williams and its other subsidiaries and other affiliates, on the other hand, will terminate, except certain agreements and arrangements which are expressly identified as intended to survive the separation.

This Offering. The separation and distribution agreement will require us to use commercially reasonable efforts to consummate this offering.

The Distribution. The separation and distribution agreement will govern the rights and obligations of Williams and us regarding the proposed distribution by Williams to its common stockholders of the shares of our common stock held by Williams. We will be required to cooperate with Williams to accomplish the distribution and, at Williams discretion, promptly take any and all actions necessary or desirable to effect the distribution.

In the separation and distribution agreement, Williams will represent its intention to complete the distribution during 2012. However, the completion of the distribution will be subject to various conditions that must be satisfied or waived by Williams in its sole discretion. In addition, Williams will have the right not to complete the distribution if, at any time, Williams board of directors determines, in its sole discretion, that the distribution is not in the best interest of Williams or its stockholders. As a result, we cannot assure you as to when or whether the distribution will occur.

Representations and Warranties. Except as expressly set forth in the separation and distribution agreement or in any other ancillary agreement, neither we nor Williams will make any representation or warranty in connection with our separation from Williams, this offering or the distribution.

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Contractual Restrictions. For so long as Williams owns at least 50% of the total voting power of our outstanding stock generally entitled to elect our directors, we will not (without Williams prior written consent):

- take any action that would limit the ability of Williams to transfer its shares of our common stock or limit the rights of any transferee of Williams as a holder of our common stock;

- issue any shares of our capital stock, or any rights, warrants or options to acquire our capital stock, if the issuance would cause Williams to own less than 50% of the total value of all classes of our outstanding capital stock, 80% of the total voting power of all classes of our outstanding capital stock generally entitled to elect our directors or 80% of any class of outstanding capital stock not entitled to vote; or

- take any action, or fail to take any action, to the extent such action or failure could reasonably result in Williams being in breach or default under a contract of which Williams has notified us.

We will agree in the separation and distribution agreement that we will not (without Williams prior written consent) take any of the following actions prior to the spin-off:

- acquire any businesses or assets with an aggregate value of more than $50 million for all such acquisitions;

- dispose of any assets with an aggregate value of more than $50 million for all such dispositions; and

- acquire any equity or debt securities of any other person with an aggregate value of more than $50 million for all such acquisitions.

In addition, for so long as Williams is required to consolidate our results of operations and financial position, we will agree not to incur any additional indebtedness (excluding the Credit Facility and the Notes) without the consent of Williams.

During the term of the administrative services agreement and the transition services agreement, and for one year thereafter, neither we nor Williams will be permitted to solicit each other s employees for employment without the other s consent.

Financial Reporting. We will agree, for so long as Williams is required to consolidate our results of operations and financial position, to:

- comply with all requirements under applicable law regarding disclosure controls and procedures and internal control over financial reporting;

- maintain internal systems and procedures that will provide Williams with reasonable assurance that our financial statements and other publicly reported information is reliable and timely prepared in accordance with GAAP and any other applicable law;

- provide Williams with financial reports, including consolidated financial statements (and notes thereto) and discussion and analysis by management of our financial condition and liquidity, in the form, and in accordance with the dates, specified by Williams;

- unless required by law, use the auditors (and lead audit partners) directed by Williams; and unless required by law, to the extent requested by Williams, keep our accounting practices and principles consistent with those of Williams.

Releases. Except as otherwise provided in the separation and distribution agreement, each of Williams and us will release and discharge the other and their respective subsidiaries and other affiliates from all liabilities existing or arising from any acts or events occurring or failing to occur or alleged to have occurred or to have failed to occur or any conditions existing or alleged to have existed on or before the separation from Williams. The releases will not extend to obligations or liabilities under any agreements between Williams and us that remain in effect following the separation, which agreements include, but are not limited

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to, the separation and distribution agreement, the administrative services agreement, the transition services agreement, the registration rights agreement and the tax sharing agreement.

Confidentiality. Each party will agree to treat as confidential and not disclose confidential information of the other party except in specific circumstances identified in the separation and distribution agreement.

Further Assurances. Each party will agree to use its reasonable best efforts to take or cause to be taken all actions, and to do or cause be done all things reasonably necessary, proper or advisable under applicable law, regulations and agreements to consummate and make effective the transactions contemplated by the separation and distribution agreement and the ancillary agreements.

Indemnification. The separation and distribution agreement will provide that we will indemnify, defend and hold harmless Williams, its subsidiaries, and each of their respective current, former and future directors, officers and employees, and each of the heirs, executors, successors and assigns of any of the foregoing for any losses arising out of or resulting from:

- the liabilities being assumed by us pursuant to the separation and distribution agreement;

- the operation of our business;

- any breach by us of the separation and distribution agreement or the ancillary agreements; and

- any untrue statement or alleged untrue statement of a material fact or omission or alleged omission to state a material fact required to be stated therein or necessary to make the statements therein not misleading, with respect to all information (i) contained in the registration statement of which this prospectus is a part or in this prospectus, (ii) contained in any public filings made by us with the SEC following the separation; and (iii) provided by us to Williams specifically for inclusion in Williams annual or quarterly reports following the separation.

Williams will indemnify, defend and hold harmless us, our subsidiaries, and each of our and their respective current, former and future directors, officers and employees, and each of the heirs, executors, successors and assigns of any of the foregoing for any losses arising out of or resulting from:

- the liabilities being retained by Williams pursuant to the separation and distribution agreement;

- the operation of Williams business;

- any breach by Williams of the separation and distribution agreement or the ancillary agreements; and

- certain pending or threatened litigation related to the 2000-2001 California Energy Crisis and the reporting of certain natural gas-related information to trade publications.

The separation and distribution agreement will also specify procedures with respect to claims subject to indemnification and related matters.

Termination. The separation and distribution agreement will be terminable before the separation in the sole discretion of Williams. In the event of such a termination, no party will have any liability or further obligation with respect to the separation and distribution agreement.

Dispute Resolution. In the event of a dispute relating to the separation and distribution agreement between us and our subsidiaries and other affiliates, on the one hand, and Williams and its other subsidiaries and other affiliates, on the other hand, the separation and distribution agreement will provide for the following procedures:

first, the parties will use commercially reasonable efforts to resolve the dispute through negotiations between our representatives and Williams representatives;

if negotiations fail, then the parties will attempt to resolve the dispute through non-binding mediation; and

if mediation fails, then the parties may seek relief in any court of competent jurisdiction.

Expenses. Except as expressly set forth in the separation and distribution agreement or in any other ancillary agreement, all fees and expenses incurred in connection with our separation from Williams will be paid by the party incurring such fees or expenses.

Administrative Services and Transition Services Agreements

We will enter into an administrative services agreement and a transition services agreement with Williams under which Williams will provide to us, on an interim basis, various corporate support services. These services will consist generally of the services that have been provided to WPX on an intercompany basis prior to this offering. These services relate to:

- cash management and treasury administration;
- finance and accounting;
- tax;
- internal audit;
- investor relations;
- payroll and human resource administration;
- information technology;
- legal and government affairs;
- insurance and claims administration;
- records management;
- real estate and facilities management;
- sourcing and procurement; and
- mail, print and other office services.

Pursuant to the administrative services agreement, Williams will provide these services to us for the period beginning on the date this offering is completed and ending on the earlier of (i) the date immediately prior to the distribution date or (ii) sixty days notice by Williams if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law. Williams will provide the services and we will pay Williams costs, including Williams direct and indirect administrative and overhead charges allocated in accordance with Williams regular and consistent accounting practices. Pursuant to the transition services agreement, Williams will provide certain services for up to one year after the distribution date. The transition services agreement may be terminated by either us or Williams upon 60 days notice after the distribution date. In addition, Williams may immediately terminate any of the services it provides under the transition services agreement if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law.

Williams may decline to provide certain services under these agreements if the provision of such services causes Williams to violate applicable law, creates a conflict of interest, requires Williams to retain additional employees or other resources or the provision of such services become impracticable due to reasons outside the control of Williams. Williams will charge us for its full salary and benefits costs associated with individuals providing the services as well as any out-of-pocket expenses incurred by Williams in the provision of the services, plus, during the term of the transition services agreement, an administrative fee.

In both cases, Williams will provide these services with the same general degree of care, at the same general volumes and at the same general degree of accuracy and responsiveness, as when the services were performed prior to the separation.

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In addition, in the event that Williams determines that it will require any services from us after the distribution date, the transition services agreement will permit Williams to request such services from us prior to the distribution date. If Williams makes such a request, we will use commercially reasonable efforts to provide such services on the same terms and conditions as those governing the services Williams is providing to us under the transition services agreement.

Registration Rights Agreement

The registration rights agreement provides Williams with rights relating to the shares of our common stock held by Williams. Under the registration rights agreement, Williams has the right, subject to the terms of its lock-up agreement with the underwriters, to require us to register for offer and sale all or a portion of the shares of our common stock covered by the agreement.

Shares Covered. The registration rights agreement covers those shares of our common stock that are held by Williams or a transferee of Williams.

Demand Registration. Williams may request registration under the Securities Act of all or any portion of our shares covered by the registration rights agreement, and we will be obligated, subject to limited exceptions, to register such shares as requested by Williams. The maximum number of registrations Williams may require us to effect is five. Williams has the right to designate the terms of each offering it requests.

We are not required to undertake any demand registration requested by Williams within 90 days after completion of a previously-requested demand registration other than pursuant to a shelf registration statement. In addition, we have the right, which may be exercised once in any 12-month period, to postpone the filing or effectiveness of any demand registration if we determine in the good faith judgment of our general counsel, confirmed by our board of directors, that such registration would reasonably be expected to require the disclosure of material information that we have a business purpose to keep confidential and the disclosure of which would have a material adverse effect on any then-active proposals to engage in certain material transactions until the earlier of (i) 15 business days after the date of disclosure of such material information, or (ii) 75 days after we make such determination.

Piggy-Back Registration. If we at any time intend to file on our behalf or on behalf of any of our other security holders a registration statement in connection with a public offering of any of our securities on a form and in a manner that would permit the registration for offer and sale of the shares of our common stock, Williams has the right to have those shares included in that offering.

Registration Expenses. We are responsible for all registration expenses incurred in connection with the performance of our obligations under the registration rights agreement. Williams is responsible for all of the fees and expenses of counsel to Williams, any applicable underwriting discounts or commissions, and any registration or filing fees incurred with respect to shares of our common stock being sold under the registration rights agreement.

Indemnification. The registration rights agreement contains indemnification and contribution provisions by us for the benefit of Williams and its affiliates and representatives and, in limited situations, by Williams for the benefit of us and any underwriters with respect to information included in any registration statement, prospectus or related documents.

Transfer. Williams may transfer shares covered by the registration rights agreement and the holders of such transferred shares will be entitled to the benefits of the registration rights agreement, provided that each such transferee agrees to be bound by the terms of the registration rights agreement.

Duration. The registration rights under the registration rights agreement will remain in effect with respect to any shares of common stock covered by the agreement until:

such shares have been sold pursuant to an effective registration statement under the Securities Act;

such shares have been sold to the public pursuant to Rule 144 under the Securities Act;

such shares have been otherwise transferred and new certificates evidencing such shares have been delivered and do not bear a legend restricting further transfer of such shares, provided that subsequent public distribution of such shares does not require registration or qualification of them under the Securities Act or any similar state law;

such shares have ceased to be outstanding; or

the distribution date.

Tax Sharing Agreement

In connection with this offering, we will enter into a tax sharing agreement with Williams. The tax sharing agreement will govern the respective rights, responsibilities, and obligations of Williams and us with respect to the payment of taxes, filing of tax returns, reimbursements of taxes, control of audits and other tax proceedings, liability for taxes that may be triggered as a result of the spin-off of our stock to Williams stockholders and other matters regarding taxes. The tax sharing agreement will remain in effect until the parties agree in writing to its termination.

Tax Returns and Taxes. Williams will be responsible for the preparation and filing of all consolidated, combined, or unitary income tax returns in which we (or our subsidiaries) are included, and the payment of all taxes that relate to such returns. Williams will be entitled to make all decisions regarding the preparation of such tax returns, including the making of any tax elections, and we will be bound by such decisions. We will be responsible for the preparation, filing, and payment of all returns other than those described above that are required to be filed with respect to us or any of our subsidiaries; however, Williams may, in its discretion, assist us in preparing any such returns.

Pro Forma Returns and Reimbursements. For each tax period in which we or any of our subsidiaries are consolidated or combined with Williams for purposes of any tax return, Williams will prepare a pro forma tax return for us as if we filed our own consolidated, combined, or unitary return. Such pro forma returns will take into account all elections and methods of accounting reflected on the true returns; will only include current income, deductions, credits and losses from us (with certain exceptions); will not include any carryovers or carrybacks of any items from us for prior or subsequent periods; and will not take into account the federal Alternative Minimum Tax. For any periods shorter than a full taxable year, the pro forma return computations will be made based on a hypothetical closing of the books for us and our subsidiaries. We will reimburse Williams for any taxes shown on the pro forma tax returns, and Williams will reimburse us for any current losses or credits we recognize based on the pro forma tax returns.

Redeterminations. In the case of any tax audit adjustments, all pro forma returns and associated tax reimbursement obligations will be recomputed to give effect to such adjustments, but only for adjustments that originate from a federal audit.

Spin-off. Williams and we expect that the spin-off of our stock to Williams stockholders and any related restructuring transaction, taken together, will qualify for U.S. federal income tax purposes as a tax-free transaction under section 355 and section 368(a)(1)(D) of the Code. Williams has received a private letter ruling from the IRS and an opinion from its outside tax advisor to such effect. In connection with the private letter ruling and the opinion, we have made certain factual statements and representations regarding our company and our business, and Williams has made certain representations regarding itself and its business. In the tax sharing agreement, we and Williams will each represent and warrant that any factual statements and representations relating to our respective companies and businesses made in connection with the private letter ruling and tax opinion are true, correct, and complete, and that we have no plan or intention of taking any actions nor know of any circumstances that could cause such factual statements or representations (or any factual statements or representations in the tax sharing agreement or separation and distribution agreement) to be untrue. We and Williams will each also represent and warrant that, for a period leading up to the IPO, there was no agreement or arrangement by any of our officers or directors (or by any person with permission of our officers or directors) regarding an acquisition of more than 50% of the stock of WPX, Williams, or Apco, and that we have no current plan or intention to enter into any such agreements. In addition, we and Williams will each covenant not to take any actions that would (i) be inconsistent with any factual statement or representation made in the tax sharing agreement, the separation and distribution agreement, or in connection with the private letter ruling or tax opinion, (ii) create a material risk that the spin-off or any related restructuring transaction would fail to qualify as tax-free, or (iii) create a material risk that section 355(d) or section 355(e) of the Code would apply to the spin-off. Further, we and Williams will each agree not to take any position on a tax return that is inconsistent with the tax free treatment of the spin-off. We and Williams will also agree to notify each other if we or they become aware of a transaction that could affect the status of the spin-off or any related restructuring transaction under section 355 or section 368(a)(1)(D) of the Code, and to take reasonable action or reasonably refrain from taking action to ensure the qualification of the spin-off as tax free, unless the IRS has issued a private letter ruling or other guidance conclusively establishing that such matter or transaction does not adversely affect the tax-free nature of the spin-off. If we and Williams cannot agree on a course of action in this respect, we will be required to take the course of action consistent with applicable law that Williams reasonably determines in good faith, taking into account both our interests and Williams interests. Last, we will agree that our officers and directors will not discuss any acquisitions of our stock or the stock of any of our subsidiaries during the two-year period beginning after the spin-off without permission from Williams, such permission not to be unreasonably withheld.

Indemnities. If Williams (or any of its subsidiaries) becomes liable for any taxes because of a failure of the spin-off or any related restructuring transaction to be wholly-tax free under section 355 or section 368(a)(1)(D) of the Code, we will indemnify Williams for such taxes to the extent caused by our breach of any representations or covenants made in the tax sharing agreement, the separation and distribution agreement, or made in connection with the private letter ruling or tax opinion. Williams will indemnify us for all taxes arising from the failure of the spin-off or any related restructuring transaction to be tax-free except for those caused by us as described above.

Proceedings and Cooperation. Williams will have the right to control any tax proceedings or disputes and to make any decisions regarding taxes, payments and settlements relating to consolidated, combined, or unitary returns that include us or our subsidiaries. If a proceeding or dispute could require us to pay taxes arising from the spin-off, Williams will agree to consult with us and give us an opportunity to comment and participate in the proceeding. However, Williams retains sole discretion over all the positions taken in such proceedings, except that we will have consent rights, which have to be exercised reasonably, to approve any settlement. We and Williams will cooperate with each other in good faith regarding all provisions of the tax sharing agreement, and will retain books and records relating to the filing of returns in the agreement for 10 years.

Employee Matters Agreement

In connection with the spin-off, we will enter into an Employee Matters Agreement with Williams that will set forth our agreements with Williams as to certain employment, compensation and benefits matters.

The Employee Matters Agreement will provide for the allocation and treatment of assets and liabilities arising out of employee compensation and benefit programs in which our employees participated prior to January 1, 2012. In connection with the spin-off, we will provide benefit plans and arrangements in which our employees will participate going forward. Generally, other than with respect to equity compensation (discussed below), from and after January 1, 2012, we will sponsor and maintain employee compensation and benefit programs relating to all employees who will be transferred to us from Williams in connection with the spin-off. Notwithstanding the preceding sentence, the Employee Matters Agreement will provide that Williams will remain solely responsible for all liabilities under The Williams Companies Pension Plan, The Williams Companies Retirement Restoration Plan and The Williams Companies Investment Plus Plan. No assets and/or liabilities under any of those plans will be transferred to us or our benefit plans, and our employees will cease active participation in those plans as of January 1, 2012.

We expect that all outstanding Williams equity awards (other than stock options granted prior to January 1, 2006) held by our employees as of the spin-off will be converted into WPX equity awards, issued pursuant to a plan that we will establish. In addition, outstanding Williams stock options that were granted prior to January 1, 2006 and held by our employees and Williams other employees as of the date of the spin-off will be converted into options to acquire both WPX common stock and Williams common stock, in the same proportion and as the number of shares of WPX common stock that each holder of Williams common stock will receive in the spin-off. We expect the conversion will result in the converted award having substantially the same intrinsic value as the applicable Williams equity award as of the date of the conversion. The performance criteria applicable to any converted performance-based restricted stock unit will also be adjusted so that total stockholder return for purposes thereunder at the end of each performance period that end after the spin-off will be calculated based on the value of both the WPX common stock and the Williams common stock at the end of the applicable performance period.

The Employee Matters Agreement will also provide for transfers of employees between Williams and us. Such transfers may be effected prior to or within after the spin-off by mutual agreement between Williams and us. In such event, the recipient employer will generally be responsible for all employment-related liabilities relating to the transferred employees, and, under the Employee Matters Agreement, the transferred employees will be treated in generally the same manner as other employees of the recipient.

Information Technology Transition Costs

Williams has agreed to provide us with up to a maximum amount of $20 million with respect to certain information technology transition costs we will incur as a result of our separation from Williams. The actual amount of cash we receive from Williams at the completion of this offering will be reduced by the total amount of such information technology costs already funded by Williams in advance of this offering. As of September 30, 2011, Williams had incurred approximately $2 million related to these costs, resulting in a remaining potential reimbursement of up to approximately $18 million. See Management s Discussion and Analysis of Financial Condition and Results of Operations Management s Discussion and Analysis of Financial Condition and Liquidity Liquidity.

Office Lease

On August 25, 2011, we entered into a 10.5 year lease for our present headquarters office with Williams Headquarters Building Company, a direct subsidiary of Williams. We estimate the annual rent payable by us under the lease to be approximately $4.6 million per year.

OTHER RELATED PARTY TRANSACTIONS

In addition to the related party transactions described in Arrangements Between Williams and Our Company above, this section discusses other transactions and relationships with related persons during the past three fiscal years.

Reimbursement of Expenses of Williams

Williams charges us for the payroll and benefit costs associated with operations employees (referred to as direct employees) and carries the obligations for many employee-related benefits in its financial statements, including the liabilities related to employee retirement and medical plans. Our share of those costs is charged to us through affiliate billings and reflected in lease and facility operating and general and administrative within costs and expenses in the accompanying Combined Statement of Operations. These costs totaled $125 million, $123 million and $111 million for the years ended December 31, 2010, 2009 and 2008, respectively.

In addition, Williams charges us for certain employees of Williams who provide general and administrative services on our behalf (referred to as indirect employees). These charges are either directly identifiable or allocated to our operations. Direct charges include goods and services provided by Williams at our request. Allocated general corporate costs are based on our relative use of the service or on a three-factor formula, which considers revenues; properties and equipment; and payroll. Our share of direct general and administrative expenses and our share of allocated general corporate expenses is reflected in general and administrative expense in the Combined Statement of Operations. These costs totaled $134 million, $136 million and $128 million for the years ended December 31, 2010, 2009 and 2008, respectively. In our management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of their costs of doing business incurred by Williams.

Commodity Sales Contracts

We procure and sell natural gas for shrink replacement and fuel to Williams Partners and other Williams affiliates. We sell substantially all of the NGLs related to our production to Williams Partners. We conduct these transactions at market prices at the time of purchase. Revenues from these sales totaled $786 million, $547 million and $1,078 million for the years ended December 31, 2010, 2009 and 2008, respectively. Effective as of August 1, 2011, we agreed to sell Williams Partners all NGLs produced from our processing plants connected to the Overland Pass Pipeline for an approximate 12 year term in exchange for a price resulting from arm s length negotiations between us and Williams Partners and approved by the conflicts committee of the board of directors of the general partner of Williams Partners. We retain the option to request redelivery of products at the Mont Belvieu, Texas NGL hub for physical marketing.

In addition, through an agency agreement, we manage the jurisdictional merchant gas sales for Transcontinental Gas Pipe Line Company LLC (Transco), an indirect, wholly owned subsidiary of Williams Partners. We are authorized to make gas sales on Transco s behalf in order to manage its gas purchase obligations. Although there is no exchange of payments between us and Transco for these transactions, we receive all margins associated with jurisdictional merchant gas sales business and, as Transco s agent, assume all market and credit risk associated with such sales.

Gathering, Processing and Treating Contracts

We purchase gathering, processing and treating services from Williams Partners, primarily in the San Juan and Piceance Basins, under several contracts. We paid $163 million, $72 million and $44 million under these contracts for the years ended December 31, 2010, 2009 and 2008, respectively. The rates Williams Partners charges us to provide these services are comparable to those that Williams Partners charges to similarly-situated nonaffiliated customers.

In July 2011, we negotiated amendments to our existing gathering, processing and treating service contracts with Williams Partners in the San Juan and Piceance Basins, primarily to extend terms with corresponding adjustments in pricing resulting from arm s length negotiations between us and Williams Partners and approved by the conflicts committee of the board of directors of the general partner of Williams Partners. The amended and restated gas gathering, processing, dehydrating and treating agreement related to our Piceance Basin production was filed as an exhibit to the registration statement of which this prospectus forms a part. That amended agreement adds life-of-lease high-recovery cryogenic processing for nearly all of the gas we produce in the Piceance Basin to the original agreement s suite of basic midstream services. It reflects an adjustment in fees corresponding to the change in service and term and provides for future service expansions at market-clearing rates. We also entered into a new gathering contract with Williams Partners in the Marcellus Basin for fees resulting from arm s length negotiations between us and Williams Partners and approved by the conflicts committee of the board of directors of the general partner of Williams Partners.

Transportation Contracts

We purchase natural gas transportation services from Williams Partners. Costs for these purchases were $25 million, $28 million and $34 million for the years ended December 31, 2010, 2009 and 2008, respectively. The rates Williams Partners charges us to provide these services are comparable to those that Williams Partners charges to similarly-situated nonaffiliated customers.

We have executed a capacity commitment of 135,000 MMBtu/d on Williams Partners Transco Northeast Supply Link, which is scheduled to be in-service in the fourth quarter of 2013. Construction of the Northeast Supply Link remains subject to regulatory approvals. The transportation rate for this firm capacity commitment is $0.59/MMbtu and represents a demand payment obligation of $436MM over the 15 year life of the project. The receipt point is Transco Station 517 and the delivery point is the New York City market area.

We manage a transportation capacity contract for Williams Partners. To the extent the transportation is not fully utilized or does not recover full-rate demand expense, Williams Partners reimburses us for these transportation costs. These reimbursements to us totaled approximately $9.8 million, $9.1 million and $10.9 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Derivative Contracts

We periodically enter into derivative contracts with Williams Partners to hedge Williams Partners forecasted NGL sales and natural gas purchases. The revenues for these contracts were $14 million and $6 million for the years ended December 31, 2010 and 2009, respectively, and an expense of $3 million for the year ended December 31, 2008. We enter into offsetting derivative contracts with third parties at equivalent pricing and volumes.

Agreements Related to the Piceance Disposition

We entered into a contribution agreement and certain other agreements with Williams Partners that effected our sale to Williams Partners of certain gathering and processing assets in Colorado s Piceance Basin (the Piceance Disposition). These agreements were the result of arm s-length negotiations between Williams and the Conflicts Committee of the board of directors of the general partner Williams Partners, which is composed solely of independent directors unaffiliated with Williams.

Contribution Agreement. On November 19, 2010, we closed the Piceance Disposition as contemplated by the contribution agreement. The Piceance Disposition was made in exchange for consideration of $702 million in cash and 1,849,138 Williams Partners common units. In March 2011, the Williams Partners common units we received in this transaction were distributed to Williams in a dividend.

Conveyance, Contribution, and Assumption Agreement. In connection with the closing of the Piceance Disposition, the parties to the contribution agreement entered into a conveyance, contribution, and assumption agreement. This conveyance, contribution, and assumption agreement effected the contribution of the contributed interests from us to Williams Partners.

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Piceance Omnibus Agreement. Under an omnibus agreement entered into in connection with the Piceance Disposition, we are obligated to reimburse Williams Partners for (i) amounts incurred by Williams Partners for any costs required to complete the pipeline and compression projects known collectively as the Ryan Gulch Expansion Project, (ii) amounts incurred by Williams Partners prior to January 31, 2011 related to the development of a cryogenic processing arrangement with a subsidiary of ours, up to $20 million, and (iii) amounts incurred by Williams Partners for notice of violation or enforcement actions related to compression station land use permits or other losses, costs and expenses related certain surface lease use agreements. As of December 31, 2010, we paid obligations of Williams Partners related to the Ryan Gulch Expansion Project of $2.9 million. Williams Partners is obligated to reimburse us for any costs related to the pipeline and compression projects known collectively as the Kokopelli Expansion irrespective of whether those costs were incurred prior to the effective date of the Piceance Disposition. We received $432,000 in reimbursements for the Kokopelli Expansion for the year ended December 31, 2010.

Transition Services Agreement. We provide transition services to Williams Partners related to the Piceance Disposition. As of December 31, 2010, we incurred expenses of $3 million for which we were reimbursed by Williams Partners pursuant to this agreement.

Meter Agency Agreements. We have agreed to provide for the operation, calibration and maintenance of certain meters for the benefit of Williams Partners. It is anticipated that payments under these agreements will be approximately $275,000 in 2011.

Procedures for Review and Approval of Related Party Transactions

Our board of directors will adopt written procedures for approving related party transactions prior to the completion of this offering. Pursuant to these procedures, the members of our board of directors who are determined by the board to be both independent under applicable rules of the NYSE and independent from Williams (the unaffiliated directors) shall be responsible for reviewing and approving entry into any transaction with Williams or its affiliates. Our Audit Committee will be responsible for reviewing and approving entry into any other transactions with related persons (as defined in the regulations of the SEC), provided, however, that if such transaction involves a member of the board, it must be reviewed and approved by the full board. If it is impractical to convene an Audit Committee meeting before a related party transaction that is subject to Audit Committee approval occurs, the chair of the Audit Committee has the authority to review and approve the transaction. No director may participate in any review, consideration or approval of any related party transaction with respect to which such director or any of his or her immediate family members is the related person.

In considering related party transactions under their authority, the Audit Committee, the Audit Committee chair, the full board, or the unaffiliated directors, as the case may be (each such group being referred to herein as an approving entity), in good faith, may approve only those related person transactions that are in, or not inconsistent with, our best interests and the best interests of our stockholders. In conducting a review of whether a transaction is in, or is not inconsistent with, our best interests and those of our stockholders, the approving entity will consider the benefits of the transaction to us, the availability of other sources for comparable products or services, the terms of the transaction, the terms available to unrelated third parties and to employees generally, and the nature of the relationship between us and the related party, among other things. All related party transactions required to be disclosed in our filings with the SEC will be so disclosed in accordance with applicable laws, rules and regulations. The agreements with Williams described under the heading Arrangements Between Williams and our Company were approved by our board of directors in advance of this offering, prior to the adoption of these procedures.

DESCRIPTION OF OUR CONCURRENT FINANCING TRANSACTIONS

Concurrent with or shortly following this offering, we expect that we will issue up to $1.5 billion in aggregate principal amount of senior unsecured notes. We expect our senior unsecured credit facility to become effective prior to the completion of this offering. The following summary is a description of the principal terms of the Notes and the Credit Facility. This offering of our common stock is not contingent upon the effectiveness of the Credit Facility or the completion of the Notes Offering.

Notes

We expect to offer and sell the Notes only to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to certain non-U.S. persons in transactions outside the United States in reliance on Regulation S under the Securities Act. We do not expect to register the offer and sale of the Notes under the Securities Act and, as a result, the Notes may not be offered and sold in the United States absent registration or an applicable exemption from registration requirements. This prospectus shall not be deemed to be an offer to sell or a solicitation of an offer to buy the Notes.

We expect the Notes will bear interest at a fixed rate agreed to by us and the initial purchasers in the Notes Offering. In connection with the Notes Offering, we expect to enter into a registration rights agreement that will obligate us to file an exchange offer registration statement for the exchange of the Notes for a new issue of substantially identical debt securities, the issuance of which has been registered under the Securities Act, as evidence of the same underlying obligation of indebtedness.

Credit Facility

On June 3, 2011 we entered into a $1.5 billion, five-year senior unsecured revolving credit facility agreement that we expect to become effective prior to the completion of this offering, upon the satisfaction of certain conditions. The Credit Facility may, under certain conditions, be increased by an additional $300 million. Funds may be borrowed under two methods of calculating interest: a fluctuating base rate equal to the lender s base rate plus an applicable margin, or a periodic base rate equal to LIBOR plus an applicable margin. The applicable margin and the commitment fee are based on our senior unsecured long-term debt ratings. The Credit Facility contains various covenants consistent with like companies unsecured credit facilities, with similar credit ratings in the industry. These covenants limit, among other things, our and our subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of our assets, enter into certain affiliate transactions and allow any material change in the nature of our or our subsidiaries businesses. Significant financial covenants under the Credit Facility include:

- a ratio of Consolidated Indebtedness to Consolidated Total Capitalization (as such terms will be defined in the Credit Facility) no greater than 60% for us and our consolidated subsidiaries as calculated at the end of each fiscal quarter; and

- at all times prior to our senior unsecured debt being rated as investment grade with a stable outlook, an additional covenant will require a minimum ratio of Net Present Value of Projected Future Cash Flows from Proved Reserves to Consolidated Indebtedness (as defined in the Credit Facility) for us and our consolidated subsidiaries as calculated at the end of each fiscal quarter. This covenant would fall away if and when an investment grade rating with a stable outlook is received.

The Credit Facility includes customary events of default. If an event of default occurs under the Credit Facility, the lenders will be able to terminate the commitments and accelerate the maturity of any loans under the Credit Facility and exercise other rights and remedies.

DESCRIPTION OF CAPITAL STOCK

The following is a description of the material terms of our capital stock as to be provided in our amended and restated certificate of incorporation and amended and restated bylaws, as each is anticipated to be in effect upon the completion of this offering. We also refer you to our amended and restated certificate of incorporation and amended and restated bylaws, copies of which are filed as exhibits to the registration statement of which this prospectus forms a part.

Authorized Capitalization

Following completion of this offering, our authorized capital stock will consist of (i) 2,000,000,000 shares of common stock, par value $.01 per share and (ii) 100,000,000 shares of preferred stock, par value $.01 per share.

Authorized but unissued shares of our capital stock may be used for a variety of corporate purposes, including future public offerings, to raise additional capital or to facilitate acquisitions. The Delaware General Corporation Law does not require stockholder approval for any issuance of authorized shares. However, the listing requirements of the NYSE, which would apply so long as our common stock is listed on the NYSE, require stockholder approval of certain issuances equal to or exceeding 20% of the then outstanding voting power or then outstanding number of shares of common stock.

Common Stock

Voting Rights

Each share of our common stock entitles its holder to one vote in the election of each director. No share of our common stock affords any cumulative voting rights. This means that the holders of a majority of the voting power of the shares voting for the election of directors can elect all directors to be elected if they choose to do so, subject to any voting rights granted to holders of any preferred stock. Generally, except as discussed in Anti-Takeover Effects of Certificate of Incorporation and Bylaws Provisions, all matters to be voted on by stockholders must be approved by a majority of the total voting power of the common stock present in person or represented by proxy at a meeting at which a quorum exists, subject to any voting rights granted to holders of any preferred stock. Except as otherwise provided by law or in the amended and restated certificate of incorporation (as further discussed in Anti-Takeover Effects of Certificate of Incorporation and Bylaws Provisions), and subject to any voting rights granted to holders of any outstanding preferred stock, amendments to the amended and restated certificate of incorporation must be approved by a majority of the votes entitled to be cast by the holders of common stock.

Dividends

Holders of our common stock will be entitled to dividends in such amounts and at such times as our board of directors in its discretion may declare out of funds legally available for the payment of dividends. Dividends on our common stock will be paid at the discretion of our board of directors after taking into account various factors, including:

- our financial condition;
- our results of operations;
- our capital requirements and development expenditures;

our future business prospects; and

any restrictions imposed by future debt instruments.

Other Rights

On liquidation, dissolution or winding up of WPX, after payment in full of the amounts required to be paid to holders of preferred stock, if any, all holders of common stock are entitled to receive the same amount per share with respect to any distribution of assets to holders of shares of common stock.

No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

Upon completion of this offering, all the outstanding shares of our common stock will be validly issued, fully paid and nonassessable.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our board of directors to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action by you. Our board of directors is able to determine, with respect to any series of preferred stock, the terms and rights of that series, including the following:

- the designation of the series;
- the number of shares of the series, which our board may, except where otherwise provided in the preferred stock designation, increase or decrease, but not below the number of shares then outstanding;
- whether dividends, if any, will be cumulative or non-cumulative and the dividend rate of the series;
- the dates at which dividends, if any, will be payable;
- the redemption rights and price or prices, if any, for shares of the series;
- the terms and amounts of any sinking fund provided for the purchase or redemption of shares of the series;
- the amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding-up of the affairs of our company;
- whether the shares of the series will have conversion privileges and if so, the terms and conditions of such privileges, including provision for adjustment of the conversion rate, if any;
- restrictions on the issuance of shares of the same series or of any other class or series; and
- the voting rights, if any, of the holders of the series.

Provisions of Amended and Restated Certificate of Incorporation Governing Corporate Opportunities

After the completion of this offering, Williams will remain a substantial stockholder of ours until it completes the spin-off of our stock to Williams stockholders or otherwise disposes of our common stock that it owns. We and Williams are engaged in similar activities or lines of business and have an interest in the same areas of corporate opportunities. Williams will not have a duty to refrain from engaging directly or indirectly in the same or similar business activities or lines of business as us, and to the fullest extent permitted by law, neither Williams nor any of its directors or officers will be liable to us or our stockholders for breach of any fiduciary duty, by reason of any such activities. Additionally, if Williams acquires knowledge of a potential transaction or matter that may be a corporate opportunity for Williams and us, to the fullest extent permitted by law, Williams will have no duty to communicate or offer such corporate opportunity to us and will not be liable to us or our stockholders for breach of any duty (fiduciary or otherwise) if Williams pursues or acquires such corporate opportunity for itself or directs such corporate opportunity to its affiliates. If any director or officer of Williams who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to Williams (or its affiliates) and that director or officer will not to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the opportunity or (2) acted in bad faith or in a manner inconsistent with the best interests of our company or our stockholders. See Risk Factors Risks Related to Our Relationship with Williams Pursuant to the terms of our amended and restated certificate of incorporation, Williams is not required to offer corporate opportunities to us, and certain of our directors and officers are permitted to offer certain corporate opportunities to Williams before us.

The provisions in our amended and restated certificate of incorporation governing corporate opportunities between Williams and us will automatically terminate, expire and have no further force and effect once (1) Williams and its subsidiaries (excluding us and our subsidiaries) cease to beneficially own shares of capital stock representing 50% or more of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors and (2) no person who is a director or officer of Williams is also a director or officer of ours. At that point, any such activities will be governed by Delaware law generally.

Anti-Takeover Effects of Certificate of Incorporation and Bylaws Provisions

Some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make the following more difficult, although they have little significance while we are controlled by Williams:

- acquisition of us by means of a tender offer or merger;
- acquisition of us by means of a proxy contest or otherwise; or
- removal of our incumbent officers and directors.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions also are designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of the potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure our company outweigh the disadvantages of discouraging those proposals because negotiation of them could result in an improvement of their terms.

Classified Board

Our amended and restated certificate of incorporation provides that our board of directors is divided into three classes. The term of the first class of directors expires at our 2012 annual meeting of stockholders, the term of the second class of directors expires at our 2013 annual meeting of stockholders and the term of the third class of directors expires at our 2014 annual meeting of stockholders. At each of our annual meetings of stockholders, the successors of the class of directors whose term expires at that meeting of stockholders will be elected for a three-year term, one class being elected each year by our stockholders. This system of electing and removing directors may discourage a third party from making a tender offer or otherwise attempting to obtain control of us if Williams no longer controls us because it generally makes it more difficult for stockholders to replace a majority of our directors.

Election and Removal of Directors

A director nominee shall be elected to our board of directors if the votes cast for such nominee s election exceed the votes cast against such nominee s election.

Directors may be removed, with or without cause, by the affirmative vote of shares representing a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors as long as Williams owns shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors. Once Williams ceases to own shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, our amended and restated certificate of incorporation requires that directors may only be removed for cause and only by the affirmative vote of not less than 75% of votes entitled to be cast by the outstanding capital stock in the election of our board of directors.

Size of Board and Vacancies

Our amended and restated certificate of incorporation provides that the number of directors on our board of directors will be fixed exclusively by our board of directors. Newly created directorships resulting from any increase in our authorized number of directors will be filled solely by the vote of our remaining directors in office. Any vacancies in our board of directors resulting from death, resignation, retirement, disqualification, removal from office or other cause will be filled solely by the vote of our remaining directors in office; provided, however, that as long as Williams continues to beneficially own shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors and such vacancy was caused by the action of stockholders, then such vacancy also may be filled by the affirmative vote of shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors.

Stockholder Action by Written Consent

Our amended and restated certificate of incorporation permits our stockholders to act by written consent without a meeting as long as Williams continues to beneficially own shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors. Once Williams ceases to beneficially own at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, our amended and restated certificate of incorporation eliminates the right of our stockholders to act by written consent.

Stockholder Meetings

Our amended and restated certificate of incorporation and amended and restated bylaws provide that a special meeting of our stockholders may be called only by (i) Williams, so long as it beneficially owns at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, (ii) our board of directors, or (iii) the chairman of our board of directors with the concurrence of a majority of our board of directors.

Amendments to Certain Provisions of our Bylaws

Our amended and restated certificate of incorporation and amended and restated bylaws provide that the provisions of our bylaws relating to the calling of meetings of stockholders, notice of meetings of stockholders, stockholder action by written consent, advance notice of stockholder business or director nominations, the authorized number of directors, the classified board structure, the filling of director vacancies or the removal of directors (and any provision relating to the amendment of any of these provisions) may only be amended by the vote of a majority of our entire board of directors or, as long as Williams owns shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, by the vote of holders of a majority of the votes entitled to be cast by outstanding capital stock in the election of our board of directors. Once Williams ceases to own shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, our amended and restated certificate of incorporation and amended and restated bylaws provide that these provisions may only be amended by the vote of a majority of our entire board of directors or by the vote of holders of at least 75% of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors.

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Amendment of Certain Provisions of our Certificate of Incorporation

The amendment of any of the above provisions in our amended and restated certificate of incorporation requires approval by holders of shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, as long as Williams owns shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors. Once Williams ceases to own shares representing at least a majority of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, our amended and restated certificate of incorporation and amended and restated bylaws provide that these provisions may only be amended by the vote of a majority of our entire board of directors followed by the vote of holders of at least 75% of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors.

Requirements for Advance Notification of Stockholder Nominations and Proposals

Our amended and restated bylaws establish advance notice procedures with respect to stockholder proposals and nomination of candidates for election as directors other than nominations made by or at the direction of our board of directors or a committee of our board of directors.

No Cumulative Voting

Our amended and restated certificate of incorporation and amended and restated bylaws do not provide for cumulative voting in the election of directors.

Undesignated Preferred Stock

The authorization of our undesignated preferred stock makes it possible for our board of directors to issue our preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes of control of our management.

Delaware Anti-Takeover Statute

For so long as Williams beneficially owns shares representing at least 15% of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, Section 203 of the Delaware General Corporation Law, which relates to business combinations with interested stockholders, shall not apply to us. Once Williams ceases to beneficially own shares representing at least 15% of the votes entitled to be cast by the outstanding capital stock in the election of our board of directors, Section 203 of the Delaware General Corporation Law will apply to us. Subject to specific exceptions, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless:

- the business combination, or the transaction in which the stockholder became an interested stockholder is approved by the board of directors prior to the date the interested stockholder attained that status;

- upon completion of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding for purposes of determining the voting stock outstanding and not outstanding, voting stock owned by the interested stockholder, those shares owned by persons who are directors and also officers, and employee stock plans in which employee participants do not have the right to determine confidentiality whether shares held subject to the plan will be tendered in a tender or exchange offer); or

on or subsequent to the date a person became an interested stockholder, the business combination is approved by the board of directors and authorized at an annual or special meeting of stockholders by the affirmative vote of at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Business combinations include mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. Subject to various exceptions, an interested stockholder is a person who, together with his or her affiliates and associates, owns, or within the previous three years did own, 15% or more of the corporation s outstanding voting stock. These restrictions could prohibit or delay the accomplishment of mergers or other takeover or change in control attempts with respect to us and, therefore, may discourage attempts to acquire us.

Limitations on Liability and Indemnification of Officers and Directors

The Delaware General Corporation Law authorizes corporations to limit or eliminate the personal liability of directors to corporations and their stockholders for monetary damages for breaches of directors fiduciary duties. Under our amended and restated certificate of incorporation, subject to limitations imposed by the Delaware General Corporation Law, no director shall be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability:

for any breach of the director s duty of loyalty to the corporation or its stockholders;

for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;

pursuant to Section 174 of the Delaware General Corporation Law (providing for liability of directors for unlawful payment of dividends or unlawful stock purchases or redemptions); or

for any transaction from which a director derived an improper personal benefit.

Our amended and restated bylaws provide that we must indemnify our directors and officers to the fullest extent authorized by the Delaware General Corporation Law. We are also expressly authorized to advance certain expenses (including attorneys fees and disbursements and court costs) and carry directors and officers insurance providing indemnification for our directors, officers and certain employees for some liabilities. We believe that these indemnification provisions and insurance are useful to attract and retain qualified directors and executive officers. There is currently no pending material litigation or proceeding involving any of our directors, officers or employees for which indemnification is sought.

Transfer Agent and Registrar

Computershare Trust Company, N.A. will be the transfer agent and registrar for our common stock.

Listing

Our common stock has been approved for listing on the NYSE under the symbol WPX.

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has not been any public market for our common stock, and a significant public market for our common stock may not develop or be sustained after this offering. We cannot predict what effect, if any, sales of shares of our common stock or the availability of shares of our common stock for sale will have on the prevailing market price of our common stock from time to time. The number of shares of our common stock available for future sale into the public markets is subject to legal and contractual restrictions, some of which are described below. The expiration of these restrictions will permit sales of substantial amounts of our common stock in the public market or could create the perception that these sales could occur, which could adversely affect the market price for our common stock and could make it more difficult for us to raise capital through the sale of our equity or equity-related securities at a time and price that we deem acceptable.

Upon the completion of this offering, we expect to have a total of shares of our common stock outstanding. All of the shares of our common stock sold in this offering will be freely tradable without restriction or further registration under the Securities Act, except for restricted shares held by persons who may be deemed our affiliates, as that term is defined under Rule 144 of the Securities Act. An affiliate is a person that directly, or indirectly through one or more intermediaries, controls or is controlled by us or is under common control with us.

Rule 144

In general, pursuant to Rule 144 under the Securities Act in effect on the date of this prospectus, once we have been subject to public company reporting requirements for at least 90 days, a person who is not one of our affiliates at any time during the 90 days preceding a sale and who has beneficially owned the shares of our common stock to be sold for at least six months, including the holding period of any prior owner other than our affiliates, would be entitled to sell those shares without complying with the manner of sale, volume limitation or notice provisions of Rule 144, subject to compliance with the public information requirements of Rule 144. In addition, under Rule 144, a person who is not one of our affiliates at any time during the 90 days preceding a sale, and who has beneficially owned the shares of our common stock to be sold for at least one year, including the holding period of any prior owner other than our affiliates, would be entitled to sell those shares without regard to the requirements of Rule 144. Our affiliates or persons selling on behalf of our affiliates are entitled to sell, upon expiration of the lock-up agreements described below, within any three-month period beginning 90 days after the date of this prospectus, a number of shares that does not exceed the greater of:

- 1.0% of the number of shares of common stock then outstanding, which is approximately shares of common stock upon the completion of this offering; and
- the average weekly trading volume of our common stock on the NYSE during the four calendar weeks preceding each such sale, subject to certain restrictions.

Sales under Rule 144 by our affiliates or persons selling on behalf of our affiliates are also subject to manner of sale provisions and notice requirements and to the availability of current public information about us. Rule 144 also provides that affiliates relying on Rule 144 to sell shares of our common stock that are not restricted shares must nonetheless comply with the same restrictions applicable to restricted shares, other than the holding period requirement.

Lock-up Agreements

We, our directors, certain of our officers and Williams have agreed with the underwriters not to sell or otherwise transfer or dispose of any shares of our common stock, subject to specified exceptions, during the period from the date of this prospectus continuing through the date that is 180 days after the date of this prospectus, subject to an extension in certain circumstances, except with the prior written consent of Barclays Capital Inc. and except that 120 days after the date of this prospectus, Williams will be permitted to spin-off

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all of our shares of common stock that it owns to its stockholders as described below under Spin-off. See Underwriting for a description of these provisions.

Shares Issued Under Employee Plans

We intend to file a registration statement on Form S-8 under the Securities Act to register common stock issuable under our employee plans. This registration statement is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, shares registered under such registration statement will be available for sale in the public market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates, or the lock-up agreements described above.

Registration Rights

After the completion of this offering, Williams will be entitled to certain rights with respect to the registration under the Securities Act of our common stock that it owns, under the terms of a registration rights agreement between us and Williams. See Arrangements Between Williams and Our Company Registration Rights Agreement.

Spin-off

Williams has advised us that, following the completion of this offering, it intends to distribute all of the shares of our common stock that it owns through a tax-free distribution, or spin-off, to Williams stockholders. The determination of whether, and if so, when, to proceed with the spin-off is entirely within the discretion of Williams, although Williams has indicated its intention to complete the spin-off no later than the first quarter of 2012. Williams has the sole discretion to determine the form, the structure and all other terms of any transactions to effect the spin-off. Williams will not effect the spin-off unless Williams has obtained a private letter ruling from the IRS and an opinion of its outside tax advisor, in either case reasonably acceptable to the Williams board of directors, to the effect that the distribution by Williams of the shares of our common stock held by Williams after the offering will qualify for U.S. federal income tax purposes as a tax-free transaction under section 355 and section 368(a)(1)(D) of the Code. Williams has received the private letter ruling from the IRS and the opinion from its outside tax advisor to such effect. Williams may decide not to complete the spin-off if, at any time, Williams board of directors determines, in its sole discretion, that the spin-off is not in the best interests of Williams or its stockholders. Common stock distributed to Williams stockholders in the spin-off transaction generally would be freely transferable, except for common stock received by persons who may be deemed to be our affiliates or otherwise subject to the lock-up agreements described above and under Underwriting.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of the material U.S. federal income tax considerations relating to the purchase, ownership and disposition of the shares of our common stock, as of the date hereof. This summary deals only with shares of our common stock purchased in this offering for cash and held as capital assets. Additionally, this summary does not deal with special situations. For example, this summary does not address:

- tax consequences to holders who may be subject to special tax treatment, such as dealers in securities or currencies, financial institutions, regulated investment companies, real estate investment trusts, expatriates, tax-exempt entities, traders in securities that elect to use a mark-to-market method of accounting for their securities or insurance companies;
- tax consequences to persons holding shares of our common stock as part of a hedging, integrated, or conversion transaction or a straddle or persons deemed to sell shares of our common stock under the constructive sale provisions of the Code;
- tax consequences to persons who at any time hold more than 5% of the total fair market value of any class of our stock;
- tax consequences to U.S. holders of shares of our common stock whose functional currency is not the U.S. dollar;
- tax consequences to partnerships or other pass-through entities and investors in such entities; or
- alternative minimum tax consequences, if any.

Finally, this summary does not address U.S. federal tax consequences other than income taxes (such as estate and gift tax consequences) or any state, local or foreign tax consequences.

The discussion below is based upon the provisions of the Code, and U.S. Treasury regulations, rulings and judicial decisions as of the date hereof. Those authorities may be changed, perhaps retroactively, so as to result in U.S. federal income tax consequences different from those discussed below. This summary does not address all aspects of U.S. federal income taxation and does not deal with all tax consequences that may be relevant to holders in light of their personal circumstances.

If a partnership holds shares of our common stock, the tax treatment of a partner in the partnership will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership holding shares of our common stock, you should consult your tax advisor.

If you are considering the purchase of shares of our common stock, you should consult your own tax advisors concerning the U.S. federal income tax consequences to you in light of your particular facts and circumstances and any consequences arising under the laws of any state, local, foreign or other taxing jurisdiction.

Consequences to U.S. Holders

The following is a summary of the U.S. federal income tax consequences that will apply to a U.S. holder of shares of our common stock. U.S. holder means a beneficial owner of common stock for U.S. federal income tax purposes that is:

- an individual citizen or resident of the United States;
- a corporation (or any other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if (1) it is subject to the primary supervision of a court within the United States and one or more U.S. persons have the authority to control all substantial decisions of the trust, or (2) it has a valid election in effect under applicable U.S. Treasury regulations to be treated as a U.S. person.

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Distributions

A distribution in respect of shares of our common stock generally will be treated as a dividend to the extent it is paid from current or accumulated earnings and profits. If the distribution exceeds current and accumulated earnings and profits, the excess will be treated as a nontaxable return of capital reducing the U.S. holder s tax basis in the common stock to the extent of the U.S. holder s tax basis in that stock. Any remaining excess will be treated as capital gain. Subject to certain holding period requirements and exceptions, dividends received by individual holders generally will be subject to a reduced maximum tax rate of 15% for qualified dividend income through December 31, 2012, after which the rate applicable to dividends is scheduled to return to the tax rate generally applicable to ordinary income. If a U.S. holder is a U.S. corporation, it may be eligible to claim the deduction allowed to U.S. corporations in respect of dividends received from other U.S. corporations equal to a portion of any dividends received, subject to generally applicable limitations on that deduction.

U.S. holders should consult their tax advisors regarding the holding period and other requirements that must be satisfied in order to qualify for the dividends-received deduction and the reduced maximum tax rate for qualified dividend income.

Sale, Exchange, Redemption or Certain Other Taxable Dispositions of our Common Stock

A U.S. holder will generally recognize capital gain or loss on a sale, exchange, redemption (provided the redemption is treated as a sale or exchange) or certain other taxable dispositions of our common stock. The U.S. holder s gain or loss will equal the difference between the amount realized by the U.S. holder and the U.S. holder s tax basis in the stock. The amount realized by the U.S. holder will include the amount of any cash and the fair market value of any other property received for the stock. Gain or loss recognized by a U.S. holder on a sale or exchange of stock will be long-term capital gain or loss if the holder held the stock for more than one year. Long-term capital gains of non-corporate taxpayers are generally taxed at lower rates than those applicable to ordinary income. The deductibility of capital losses is subject to certain limitations.

Information Reporting and Backup Withholding

When required, we or our paying agent will report to the holders of our common stock and to the IRS amounts paid on or with respect to the common stock during each calendar year and the amount of tax, if any, withheld from such payments. A U.S. holder will be subject to backup withholding on any dividends paid on our common stock and proceeds from the sale of our common stock at the applicable rate if the U.S. holder (a) fails to provide us or our paying agent with a correct taxpayer identification number or certification of exempt status, (b) has been notified by the IRS that it is subject to backup withholding as a result of the failure to properly report payments of interest or dividends, or (c) in certain circumstances, has failed to certify under penalty of perjury that it is not subject to backup withholding. A U.S. holder may be eligible for an exemption from backup withholding by providing a properly completed IRS Form W-9 to us or our paying agent. Any amounts withheld under the backup withholding rules will generally be allowed as a refund or a credit against a U.S. holder s U.S. federal income tax liability provided the required information is properly furnished to the IRS by the U.S. holder on a timely basis.

Consequences to Non-U.S. Holders

The following is a summary of the U.S. federal income tax consequences that will apply to you if you are a non-U.S. holder of shares of our common stock. The term non-U.S. holder means a beneficial owner of shares of common stock that is, for U.S. federal income tax purposes, an individual, corporation, trust or estate that is not a U.S. holder. Special rules may apply to certain non-U.S. holders such as controlled foreign corporations or passive foreign investment companies. Such entities should consult their own tax advisors to determine the U.S. federal, state, local and other tax consequences that may be relevant to them.

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Distributions

Any dividends paid to a non-U.S. holder with respect to the shares of our common stock will be subject to withholding tax at a 30% rate or such lower rate as specified by an applicable income tax treaty. However, dividends that are effectively connected with the conduct of a trade or business within the United States and, where an applicable tax treaty so provides, are attributable to a U.S. permanent establishment, are not subject to the withholding tax, but instead are subject to U.S. federal income tax on a net income basis at applicable graduated individual or corporate rates. Certain certification and disclosure requirements must be complied with in order for effectively connected income to be exempt from withholding. Any such effectively connected dividends received by a foreign corporation may, under certain circumstances, be subject to an additional branch profits tax at a 30% rate or such lower rate as specified by an applicable income tax treaty.

A non-U.S. holder of shares of our common stock who wishes to claim the benefit of an applicable treaty rate is required to satisfy applicable certification and other requirements. If a non-U.S. holder is eligible for a reduced rate of U.S. withholding tax pursuant to an income tax treaty, the holder may obtain a refund of any excess amounts withheld by timely filing an appropriate claim for refund with the IRS.

Sale, Exchange, Redemption or Other Taxable Disposition of our Common Stock

Any gain realized by a non-U.S. holder upon the sale, exchange, redemption (provided the redemption is treated as a sale or exchange) or other taxable disposition of shares of our common stock will not be subject to U.S. federal income tax with respect to such gain unless:

- that gain is effectively connected with the conduct of a trade or business in the United States (and, if required by an applicable income tax treaty, is attributable to a U.S. permanent establishment);

- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of that disposition, and certain other conditions are met; or

- our common stock constitutes a U.S. real property interest by reason of our status as a U.S. real property holding corporation (a USRPHC) for U.S. federal income tax purposes at any time within the shorter of the five-year period preceding the disposition or the period that the non-U.S. holder held our common stock.

A non-U.S. holder described in the first bullet point above will be subject to U.S. federal income tax on the net gain derived from the sale in the same manner as a U.S. holder. If a non-U.S. holder is eligible for the benefits of a tax treaty between the United States and its country of residence, any such gain will be subject to U.S. federal income tax in the manner specified by the treaty. To claim the benefit of a treaty, a non-U.S. holder must properly submit an IRS Form W-8BEN (or suitable successor or substitute form). A non-U.S. holder that is a foreign corporation and is described in the first bullet point above will be subject to tax on gain under regular graduated U.S. federal income tax rates and, in addition, may be subject to a branch profits tax at a 30% rate or a lower rate if so specified by an applicable income tax treaty. An individual non-U.S. holder described in the second bullet point above will be subject to a flat 30% U.S. federal income tax on the gain derived from the sale, which may be offset by U.S. source capital losses.

With regard to the third bullet point above, generally, a corporation is a USRPHC if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We expect to be a USRPHC for U.S. federal income tax purposes. However, even if we are or become a USRPHC, our common stock will be treated as a U.S. real property interest only if the non-U.S. holder actually or constructively holds more than 5% of our common stock at any time during the holding period described above, provided that our common stock does not cease to be regularly traded on an established securities market prior to the year in which the sale occurs. Any taxable gain generally would be taxed in the same manner as gain that is effectively connected with the conduct of a trade or business in the United States, except that the branch profits tax will not apply. Non-U.S. holders should consult their own advisors about the consequences that could result if we are, or become, a USRPHC.

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Information Reporting and Backup Withholding

Generally, we must report to the IRS and to non-U.S. holders the amount of dividends paid to the holder and the amount of tax, if any, withheld with respect to those payments. Copies of the information returns reporting such dividend payments and any withholding may also be made available to the tax authorities in the country in which the holder resides under the provisions of an applicable income tax treaty.

In general, a non-U.S. holder will not be subject to backup withholding with respect to payments of dividends that we make to the holder if the non-U.S. holder certifies under penalty of perjury that it is a non-U.S. holder or otherwise establishes an exemption. A non-U.S. holder will be subject to information reporting and, depending on the circumstances, backup withholding with respect to the proceeds of the sale or other disposition of shares of our common stock within the United States or conducted through certain U.S.-related payors, unless the payor of the proceeds receives the statement described above or the holder otherwise establishes an exemption.

Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against a holder s U.S. federal income tax liability provided the required information is furnished to the IRS.

New Legislation Relating to Foreign Accounts

Newly enacted legislation may impose withholding taxes on certain types of payments made to foreign financial institutions and certain other non-U.S. entities after December 31, 2012. The legislation imposes a 30% withholding tax on dividends on, or gross proceeds from the sale or other disposition of, common stock paid to a foreign financial institution unless the foreign financial institution enters into an agreement with the U.S. Treasury to, among other things, undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to account holders whose actions prevent it from complying with these reporting and other requirements. In addition, the legislation imposes a 30% withholding tax on the same types of payments to a foreign non-financial entity unless the entity certifies that it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner. Prospective investors should consult their tax advisors regarding the effect of this legislation, if any, on their ownership and disposition of the shares of our common stock.

Health Care Education and Reconciliation Act of 2010

On March 30, 2010, President Obama signed into law the Health Care Education and Reconciliation Act of 2010, which requires certain United States persons who are individuals, estates or trusts to pay a 3.8% tax on, among other things, dividends and capital gains from the sale, exchange, redemption or other taxable disposition of equity investments, including common stock, for taxable years beginning after December 31, 2012. Prospective investors should consult their tax advisors regarding the effect, if any, of this legislation on their ownership and disposition of the shares of our common stock.

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UNDERWRITING

Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as representatives of the underwriters and joint book-running managers of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement, each of the underwriters named below has severally agreed to purchase from us the respective number of common stock shown opposite its name below:

Underwriters	Number of Shares
Barclays Capital Inc.	
Citigroup Global Markets Inc.	
J.P. Morgan Securities LLC	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
Deutsche Bank Securities Inc.	
Goldman, Sachs & Co.	
Morgan Stanley & Co. LLC.	
Wells Fargo Securities, LLC	
Credit Suisse Securities (USA) LLC	
RBC Capital Markets, LLC	
Scotia Capital (USA) Inc.	
UBS Securities LLC	
Howard Weil Incorporated	
Total	

The underwriting agreement provides that the underwriters obligation to purchase shares of common stock depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the shares of common stock offered hereby (other than those shares of common stock covered by their option to purchase additional shares as described below), if any of the shares are purchased;
- the representations and warranties made by us to the underwriters are true;
- there is no material change in our business or the financial markets; and
- we deliver customary closing documents to the underwriters.

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional shares. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the shares.

	No Exercise	**Full Exercise**
Per share		
Total		

The representatives of the underwriters have advised us that the underwriters propose to offer the shares of common stock directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $ per share. After the offering, the representatives may change the offering price and other selling terms. Sales of shares made outside of the United States may be made by affiliates of the underwriters.

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The expenses of the offering that are payable by us are estimated to be approximately $4.7 million (excluding underwriting discounts and commissions). The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters right to reject any order in whole or in part.

Option to Purchase Additional Shares

We have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement, to purchase, from time to time, in whole or in part, up to an aggregate of shares at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than shares in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional shares based on the underwriter s underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting section. Any shares of common stock issued pursuant to this option will not increase the total number of shares of common stock outstanding after this offering, but rather the number of shares of common stock owned by Williams will be reduced share for share by the number of shares of common stock issued pursuant to such option, thus reducing Williams ownership interest in us. We will distribute the net proceeds from the sale of shares of common stock pursuant to this option to Williams as part of our restructuring transactions. Williams is deemed to be an underwriter with respect to any shares of common stock issued pursuant to this option.

Lock-Up Agreements

We, our directors, certain of our officers and Williams have agreed that, subject to certain exceptions, without the prior written consent of Barclays Capital Inc., we and they will not directly or indirectly, (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any shares of common stock (including, without limitation, shares of common stock that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the SEC and shares of common stock that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common stock, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any shares of common stock or securities convertible, exercisable or exchangeable into common stock or any of our other securities, or (4) publicly disclose the intention to do any of the foregoing for a period of 180 days after the date of this prospectus, except that 120 days after the date of this prospectus, Williams will be permitted to spin-off all of our shares of common stock that it owns to its stockholders.

The 180-day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the 180-day restricted period we issue an earnings release or material news or a material event relating to us occurs; or

- prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period,

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or occurrence of a material event, unless such extension is waived in writing by Barclays Capital Inc.

Barclays Capital Inc., in its sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common stock and other securities from lock-up agreements, Barclays Capital Inc. will consider, among other factors, the holder s reasons for requesting the release, the number of shares of common stock and other securities for which the release is being requested and market conditions at the time.

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Directed Share Program

At our request, the underwriters have reserved for sale at the initial public offering price up to shares of our common stock offered hereby for officers, directors, employees and certain other persons associated with us. The number of shares available for sale to the general public will be reduced to the extent such persons purchase such reserved shares. Any reserved shares not so purchased will be offered by the underwriters to the general public on the same basis as the other shares of our common stock offered hereby. Any participants in this program shall be prohibited from selling, pledging or assigning any shares sold to them pursuant to this program for a period of 180 days after the date of this prospectus. This 180-day lock up period shall be extended with respect to our issuance of an earnings release or if a material news or a material event relating to us occurs, in the same manner as described above under Lock-Up Agreements.

Offering Price Determination

Prior to this offering, there has been no public market for our common stock. The initial public offering price will be negotiated between the representatives and us. In determining the initial public offering price of our common stock, the representatives will consider:

- the history and prospects for the industry in which we compete;
- our financial information;
- the ability of our management and our business potential and earning prospects;
- the prevailing securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded shares of generally comparable companies.

Indemnification

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

Stabilization, Short Positions and Penalty Bids

The representatives may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common stock, in accordance with Regulation M under the Exchange Act:

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- A short position involves a sale by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of shares involved in the sales made by the underwriters in excess of the number of shares they are obligated to purchase is not greater than the number of shares that they may purchase by exercising their option to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in their option to purchase additional shares. The underwriters may close out any short

position by either exercising their option to purchase additional shares and/or purchasing shares in the open market. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through their option to purchase additional shares. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of the common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NYSE or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters make representation that the representatives will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representatives on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter s or selling group member s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

New York Stock Exchange

We have been approved to list our shares of common stock on the NYSE under the symbol WPX. In connection with that listing, the underwriters will undertake to sell the minimum number of common shares to the minimum number of beneficial owners necessary to meet the NYSE listing requirements.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of shares offered by them.

Stamp Taxes

If you purchase shares of common stock offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

Relationships

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, are currently performing, and may in the future perform, various financial advisory and investment banking services for us or for Williams, for which they may receive customary fees and expenses. For instance, affiliates of the underwriters are lenders, and in some cases agents, arrangers or managers for the lenders, under our Credit

Facility. An affiliate of Citigroup Global Markets Inc. is the administrative agent, Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated are the joint lead arrangers and joint bookrunners, and Barclays Capital Inc., J.P. Morgan Securities LLC and an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated are the co-syndication agents under our Credit Facility.

In the ordinary course of business, the underwriters and their respective affiliates may make or hold a broad array of investments, including serving as counterparties to certain derivative and hedging arrangements, and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of us or Williams. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

FINRA

Prior to this offering, Williams entered into certain separate engagements with Barclays Capital Inc. and Citigroup Global Markets Inc. under which Barclays Capital Inc. and Citigroup Global Markets Inc. agreed to provide financial advisory services in connection with certain strategic transactions and Williams granted a right of first refusal pursuant to which it agreed to offer to Barclays Capital Inc. and Citigroup Global Markets Inc. the right to participate in certain future financings related to such engagements. This right of first refusal is considered to be an item of value in connection with this offering pursuant to FINRA Rule 5110 and has a deemed compensation value of one percent of the offering proceeds of this offering.

Selling Restrictions

European Economic Area

In relation to each member state of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), including each Relevant Member State that has implemented the 2010 PD Amending Directive with regard to persons to whom an offer of securities is addressed and the denomination per unit of the offer of securities (each, an Early Implementing Member State), with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date), no offer of shares will be made to the public in that Relevant Member State (other than offers (the Permitted Public Offers) where a prospectus will be published in relation to the shares that has been approved by the competent authority in a Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive), except that with effect from and including that Relevant Implementation Date, offers of shares may be made to the public in that Relevant Member State at any time:

(a) to qualified investors as defined in the Prospectus Directive, including:

(i) (in the case of Relevant Member States other than Early Implementing Member States), legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities, or any legal entity which has two or more of (i) an average of at least 250 employees during the last financial year; (ii) a total balance sheet of more than 43.0 million and (iii) an annual turnover of more than 50.0 million as shown in its last annual or consolidated accounts; or

(ii) (in the case of Early Implementing Member States), persons or entities that are described in points (1) to (4) of Section I of Annex II to Directive 2004/39/EC, and those who are treated on request as professional clients in accordance with Annex II to Directive 2004/39/EC, or recognized as eligible counterparties in accordance with Article 24 of Directive 2004/39/EC unless they have requested that they be treated as non-professional clients;

(b) to fewer than 100 (or, in the case of Early Implementing Member States, 150) natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted in the Prospectus Directive, subject to obtaining the prior consent of the representatives for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of shares shall result in a requirement for the publication of a prospectus pursuant to Article 3 of the Prospectus Directive or of a supplement to a prospectus pursuant to Article 16 of the Prospectus Directive.

Each person in a Relevant Member State (other than a Relevant Member State where there is a Permitted Public Offer) who initially acquires any shares or to whom any offer is made will be deemed to have represented, acknowledged and agreed that (A) it is a qualified investor , and (B) in the case of any shares acquired by it as a financial intermediary, as that term is used in Article 3(2) of the Prospectus Directive, (x) the shares acquired by it in the offering have not been acquired on behalf of, nor have they been acquired with a view to their offer or resale to, persons in any Relevant Member State other than qualified investors as defined in the Prospectus Directive, or in circumstances in which the prior consent of the Subscribers has been given to the offer or resale, or (y) where shares have been acquired by it on behalf of persons in any Relevant Member State other than qualified investors as defined in the Prospectus Directive, the offer of those shares to it is not treated under the Prospectus Directive as having been made to such persons.

For the purpose of the above provisions, the expression an offer to the public in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer of any shares to be offered so as to enable an investor to decide to purchase any shares, as the same may be varied in the Relevant Member State by any measure implementing the Prospectus Directive in the Relevant Member State and the expression Prospectus Directive means Directive 2003/71 EC (including the 2010 PD Amending Directive, in the case of Early Implementing Member States) and includes any relevant implementing measure in each Relevant Member State and the expression 2010 PD Amending Directive means Directive 2010/73/EU.

United Kingdom

This prospectus is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the Prospectus Directive (Qualified Investors) that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as relevant persons). This prospectus and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant persons should not act or rely on this document or any of its contents.

Switzerland

The shares may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange (SIX) or on any other stock exchange or regulated trading facility in Switzerland. This document has been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this document nor any other offering or marketing material relating to the shares or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this document nor any other offering or marketing material relating to the offering, the Company, the shares have been or will be filed with or approved by any Swiss regulatory authority. In particular, this document will not be filed with, and the offer of shares will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA, and the offer of shares has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes (CISA). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of shares.

Dubai International Financial Centre

This prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority (DFSA). This prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus. The shares to which this prospectus relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the shares offered should conduct their own due diligence on the shares. If you do not understand the contents of this prospectus you should consult an authorized financial advisor.

Australia

No prospectus or other disclosure document (as defined in the Corporations Act 2001 (Cth) of Australia (Corporations Act)) in relation to the shares has been or will be lodged with the Australian Securities & Investments Commission (ASIC). This document has not been lodged with ASIC and is only directed to certain categories of exempt persons. Accordingly, if you receive this document in Australia:

(a) you confirm and warrant that you are either:

  (i) a sophisticated investor under section 708(8)(a) or (b) of the Corporations Act;

  (ii) a sophisticated investor under section 708(8)(c) or (d) of the Corporations Act and that you have provided an accountant s certificate to us which complies with the requirements of section 708(8)(c)(i) or (ii) of the Corporations Act and related regulations before the offer has been made;

  (iii) a person associated with the Company under section 708(12) of the Corporations Act; or

  (iv) a professional investor within the meaning of section 708(11)(a) or (b) of the Corporations Act,

and to the extent that you are unable to confirm or warrant that you are an exempt sophisticated investor, associated person or professional investor under the Corporations Act any offer made to you under this document is void and incapable of acceptance; and

(b) you warrant and agree that you will not offer any of the shares for resale in Australia within 12 months of those shares being issued unless any such resale offer is exempt from the requirement to issue a disclosure document under section 708 of the Corporations Act.

Hong Kong

The shares may not be offered or sold in Hong Kong, by means of any document, other than (a) to professional investors as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made under that Ordinance or (b) in other circumstances which do not result in the document being a prospectus as defined in the Companies Ordinance (Cap. 32, Laws of Hong Kong) or which do not constitute an offer to the public within the meaning of that Ordinance. No advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of the issue, whether in Hong Kong or elsewhere, which is directed at, or the contents of which are likely to be read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to the shares which are intended to be disposed of only to persons outside Hong Kong or only to professional investors as defined in the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) or any rules made under that Ordinance.

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India

This prospectus has not been and will not be registered as a prospectus with the Registrar of Companies in India or with the Securities and Exchange Board of India. This prospectus or any other material relating to these securities is for information purposes only and may not be circulated or distributed, directly or indirectly, to the public or any members of the public in India and in any event to not more than 50 persons in India. Further, persons into whose possession this prospectus comes are required to inform themselves about and to observe any such restrictions. Each prospective investor is advised to consult its advisors about the particular consequences to it of an investment in these securities. Each prospective investor is also advised that any investment in these securities by it is subject to the regulations prescribed by the Reserve Bank of India and the Foreign Exchange Management Act and any regulations framed thereunder.

Japan

No securities registration statement (SRS) has been filed under Article 4, Paragraph 1 of the Financial Instruments and Exchange Law of Japan (Law No. 25 of 1948, as amended) (FIEL) in relation to the shares. The shares are being offered in a private placement to qualified institutional investors (tekikaku-kikan-toshika) under Article 10 of the Cabinet Office Ordinance concerning Definitions provided in Article 2 of the FIEL (the Ministry of Finance Ordinance No. 14, as amended) (QIIs), under Article 2, Paragraph 3, Item 2 i of the FIEL. Any QII acquiring the shares in this offer may not transfer or resell those shares except to other QIIs.

Korea

The shares may not be offered, sold and delivered directly or indirectly, or offered or sold to any person for reoffering or resale, directly or indirectly, in Korea or to any resident of Korea except pursuant to the applicable laws and regulations of Korea, including the Korea Securities and Exchange Act and the Foreign Exchange Transaction Law and the decrees and regulations thereunder. The shares have not been registered with the Financial Services Commission of Korea for public offering in Korea. Furthermore, the shares may not be resold to Korean residents unless the purchaser of the shares complies with all applicable regulatory requirements (including but not limited to government approval requirements under the Foreign Exchange Transaction Law and its subordinate decrees and regulations) in connection with the purchase of the shares.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Future Act, Chapter 289 of Singapore (the SFA), (ii) to a relevant person as defined in Section 275(2) of the SFA, or any person pursuant to Section 275 (1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed and purchased under Section 275 of the SFA by a relevant person which is:

(a) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(b) a trust (where the trustee is not an accredited investor (as defined in Section 4A of the SFA)) whose sole whole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest (howsoever described) in that trust shall not be transferable within six months after that corporation or that trust has acquired the shares under Section 275 of the SFA except:

(i) to an institutional investor under Section 274 of the SFA or to a relevant person (as defined in Section 275(2) of the SFA) and in accordance with the conditions, specified in Section 275 of the SFA;

(ii) (in the case of a corporation) where the transfer arises from an offer referred to in Section 275(1A) of the SFA, or (in the case of a trust) where the transfer arises from an offer that is made on terms that such rights or interests are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets;

(iii) where no consideration is or will be given for the transfer; or

(iv) where the transfer is by operation of law.

By accepting this prospectus, the recipient hereof represents and warrants that he is entitled to receive it in accordance with the restrictions set forth above and agrees to be bound by limitations contained herein. Any failure to comply with these limitations may constitute a violation of law.

LEGAL MATTERS

The validity of the common stock offered hereby will be passed upon for us by Gibson, Dunn & Crutcher LLP. Certain legal matters in connection with the common stock offered hereby will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

Ernst & Young LLP, independent registered public accounting firm, has audited the combined financial statements and schedule at December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, as set forth in their report included in this prospectus. We have included the combined financial statements and schedule in this prospectus and elsewhere in the registration statement in reliance on Ernst & Young LLP s report, given on their authority as experts in accounting and auditing.

Approximately 94 percent of our year-end 2010 U.S. proved reserves estimates included in this prospectus were either audited by Netherland, Sewell & Associates, Inc., or, in the case of reserves estimates related to properties underlying the former Williams Coal Seam Gas Royalty Trust, were audited by Miller and Lents, Ltd.

Approximately 94 percent of our year-end 2010 proved reserves estimates for international properties were reviewed and certified by Ralph E. Davis Associates, Inc.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the common stock we propose to sell in this offering. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement. For further information about us and the common stock that we propose to sell in this offering, we refer you to the registration statement and the exhibits and schedules filed as a part of the registration statement. Statements contained in this prospectus as to the contents of any contract or other document filed as an exhibit to the registration statement are not necessarily complete. If a contract or document has been filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed as an exhibit to the registration statement. When we complete this offering, we will also be required to file annual, quarterly and special reports, proxy statements and other information with the SEC.

You can read our SEC filings, including the registration statement, over the Internet at the SEC s website at www.sec.gov. You may also read and copy any document we filed with the SEC at its public reference facility at

100 F Street, N.E., Washington, D.C. 20549. You may also obtain copies of the documents at prescribed rates by writing to the Public Reference Section of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facilities.

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WPX Energy

Unaudited Pro Forma Combined Financial Statements

Introduction

The unaudited pro forma combined financial statements are based upon the historical combined financial position and results of operations of WPX Energy (the Company), a wholly owned subsidiary of The Williams Companies, Inc. (Williams). In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business. In October 2011, Williams contributed to the Company its investment in certain subsidiaries related to its international exploration and production business. These contributions will be recorded at historical cost as they are considered to be a reorganization of entities under common control. Additionally, in June 2011, Williams contributed to capital all notes payable to Williams owed by the combined entities and, as a result, the Company has received and will receive its investment in these certain subsidiaries without debt to Williams. The unaudited pro forma combined financial statements have been derived from the Company s historical combined financial statements set forth elsewhere in this prospectus and are qualified in their entirety by reference to such historical combined financial statements and notes thereto. The unaudited pro forma combined financial statements should be read in conjunction with the notes accompanying such unaudited pro forma combined financial statements, as well as in conjunction with our historical combined financial statements and related notes thereto, Management s Discussion and Analysis of Financial Condition and Results of Operations and Use of Proceeds, each of which is included elsewhere in this prospectus.

The unaudited pro forma combined financial statements as of September 30, 2011 and for the nine months ended September 30, 2011 and year ended December 31, 2010 were derived by adjusting the Company s historical combined financial statements. The pro forma adjustments are based upon currently available information and certain estimates and assumptions; therefore, actual adjustments will differ from the pro forma adjustments. However, management believes the adjustments provide a reasonable basis for presenting the significant effects of the transactions as contemplated and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the pro forma combined financial statements. Williams has advised us that, following the completion of this offering, it intends to distribute all of the shares of our common stock it owns through a tax-free distribution, or spin-off, to Williams stockholders. The determination of whether, and if so, when, to proceed with the spin-off is entirely within the discretion of Williams, although Williams has indicated its intention to complete the spin-off no later than the first quarter of 2012. Due to the uncertainty of the spin-off, the unaudited pro forma combined financial statements do not include any adjustments related to such a spin-off of Williams ownership in the Company.

The unaudited pro forma combined statement of operations may not be indicative of the actual results that would have been achieved had the transactions been consummated on the dates indicated. Also, the unaudited pro forma combined financial statements should not be viewed as indicative of our financial condition or results of operations as of any future dates or for any future period.

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WPX Energy
Unaudited Pro Forma Combined Balance Sheet

September 30, 2011

			Pro Forma Adjustments						
	Combined Historical (a)		Restructuring Transactions		Concurrent Financing Transactions		Offering Transactions		Combined Pro Forma
					(millions)				
Assets									
Current assets:									
Cash and cash equivalents	$	50	$	$	1,479(c) (1,697)(d)	$	718(f)	$	550
Accounts receivable:									
Trade, net of allowance for doubtful accounts		444							444
Affiliate		41							41
Derivative assets		388							388
Inventories		82							82
Other		65							65
Total current assets		1,070			(218)		718		1,570
Investments		119							119
Properties and equipment, net		8,729							8,729
Derivative assets		118							118
Other noncurrent assets		105			21(c)				126
Total assets	$	10,141	$	$	(197)	$	718	$	10,662
Liabilities and Equity									
Current liabilities:									
Accounts payable:									
Trade	$	536	$	$		$		$	536
Affiliates		99							99
Accrued and other current liabilities		171							171
Deferred income taxes		93							93
Derivative liabilities		107							107
Total current liabilities		1,006							1,006
Deferred income taxes		1,656							1,656
Long-term debt					1,500(c)				1,500
Derivative liabilities		73							73

Asset retirement obligations	296				296
Other noncurrent liabilities	103	47(a)			150
Equity:					
Owner s net investment	6,729	(47)(a) (4,985)(b)	(1,697)(d)		
Accumulated other comprehensive income	200				200
Common stock, $.01 par value per share		(b)		(f)	
Additional paid-in capital		4,985(b)		718(f)	5,703
Noncontrolling interests	78				78
Total equity	7,007	(47)	(1,697)	718	5,981
Total liabilities and equity	$ 10,141	$	$ (197)	$ 718	$ 10,662

See accompanying notes to pro forma financial statements

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WPX Energy

Unaudited Pro Forma Combined Statement of Operations

	Nine Months Ended September 30, 2011			Year Ended December 31, 2010		
	Combined Historical	Pro Forma Adjustments	Combined Pro Forma	Combined Historical	Pro Forma Adjustments	Combined Pro Forma
	(Millions - except per share amounts)					
Revenues	$ 2,996	$	$ 2,996	$ 4,034	$	$ 4,034
Costs and expenses:						
Lease and facility operating expense, including affiliate	218		218	286		286
Gathering, processing and transportation, including affiliate	372		372	326		326
Taxes other than income	109		109	125		125
Gas management (including charges for unutilized pipeline capacity)	1,122		1,122	1,771		1,771
Exploration	107		107	73		73
Depreciation, depletion and amortization	703		703	875		875
Impairment of producing properties and costs of acquired unproved reserves				678		678
Goodwill impairment				1,003		1,003
General and administrative, including affiliate	208		208	253		253
Other net	4		4	(19)		(19)
Total costs and expenses	2,843		2,843	5,371		5,371
Operating income (loss)	153		153	(1,337)		(1,337)
Interest expense, including affiliate	(97)	95(a) (76)(e)	(78)	(124)	119(a) (101)(e)	(106)
Interest capitalized	8		8	16		16
Investment income and other	19		19	21		21
Income (loss) from continuing operations before income taxes	83	19	102	(1,424)	18	(1,406)
Provision (benefit) for income taxes	29	7(g)	36	(150)	6(g)	(144)

Income (loss) from continuing operations	54	12	66	(1,274)	12	(1,262)
Loss from discontinued operations	(11)		(11)	(8)		(8)
Net income (loss)	$ 43	$ 12	$ 55	$ (1,282)	$ 12	$ (1,270)
Pro forma income (loss) from continuing operations per share (Note 3):						
Basic	$		$	$		$
Diluted	$		$	$		$
Weighted average shares outstanding:						
Basic		(f)			(f)	
Diluted		(f)			(f)	

See accompanying notes to pro forma financial statements

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WPX Energy

Notes to Pro Forma Combined Financial Statements
(Unaudited)

Note 1. Basis of Presentation

The historical financial information is derived from the historical combined financial statements of WPX Energy set forth elsewhere in this prospectus and is qualified in its entirety by reference to such historical combined financial statements and notes thereto. The pro forma adjustments have been prepared as if the transactions to be effected prior to or at the completion of this offering had taken place on September 30, 2011, in the case of the unaudited pro forma combined balance sheet or as of January 1, 2010, in the case of the unaudited pro forma combined statement of operations for the year ended December 31, 2010, and the nine months ended September 30, 2011.

Upon completion of this offering, we anticipate incurring incremental general and administrative expense as a result of being a public company. No pro forma adjustment has been made for these additional expenses, as an estimate of these expenses is not objectively determinable. Additionally, we currently depend on Williams for a number of administrative functions. Prior to the completion of this offering, we will enter into an administrative services agreement under which Williams will provide to us, on an interim basis, various corporate support services. These services will consist generally of the services that have been provided to us on an intercompany basis prior to this offering and we will pay Williams costs, including Williams direct and indirect administrative and overhead charges allocated in accordance with Williams regular and consistent accounting practices. For more information regarding this agreement, see Arrangements Between Williams and Our Company.

At September 30, 2011, we have no employees, nor will we at the completion of this offering. Williams is currently evaluating the form of the employee transfers which are expected to be effective as of January 1, 2012. Williams may decide to effect this by contributing to us newly formed administrative entities. We expect such transfers will not include any significant assets, but could involve approximately $10-$15 million of employee-related liabilities. The actual amount of these employee-related liabilities will not be objectively determinable until the time when the specific employees are known. Additionally, if Williams were to proceed with the spin-off of its ownership in us, we would enter into an employee matters agreement with Williams that will set forth our agreements with Williams as to certain employment, compensation and benefit matters. For more information regarding this agreement and the presentation of employee costs in the historical financial statements, see Arrangements Between Williams and Our Company and Note 4 of Notes to Combined Financial Statements.

Williams has agreed to provide us with up to a maximum amount of $20 million with respect to certain information technology transition costs we will incur as a result of our separation from Williams. The actual amount of cash we receive from Williams at the completion of this offering will be reduced by the total amount of such information technology costs already funded by Williams in advance of this offering. As of September 30, 2011, Williams had incurred approximately $2 million related to these costs, resulting in a remaining potential reimbursement of up to approximately $18 million. The entire amount we receive from Williams will be recorded as a capital contribution from Williams upon receipt and any future amounts we spend on such information technology transition costs and expenses will be recorded as increases in our assets or expenses depending on the specific nature of the costs. No pro forma adjustment has been made for this capital contribution or the related information technology transition costs and expenses as an estimate of these costs and expenses is not objectively determinable.

Upon completion of this offering, we will enter into a tax sharing agreement with Williams. The tax sharing agreement will govern the respective rights, responsibilities and obligations of Williams and us with respect to various matters regarding taxes. The Company s domestic operations are included in the consolidated federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision presented in the Company s historical combined financial statements has been calculated on a separate return basis, except for certain state and federal tax attributes (primarily minimum tax credit

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WPX Energy

Notes to Pro Forma Combined Financial Statements (Continued)

carry-forwards) for which the actual allocation (if any) cannot be determined until the consolidated tax returns are complete for the year in which an income tax deconsolidation event occurs. For more information regarding this agreement and the presentation of income taxes in the historical financial statements, see Arrangements Between Williams and Our Company and Note 10 of Notes to Combined Financial Statements.

Note 2. Pro Forma Adjustments

Restructuring Transactions

(a) In July 2011, in accordance with our planned separation from Williams, Williams contributed its investment in certain subsidiaries related to its domestic exploration and production business to us. In October 2011, Williams contributed its investment in certain subsidiaries related to its international exploration and production business to us. Our separation and distribution agreement with Williams also provides certain indemnifications to us related to these contributions. These contributions have or will be recorded at historical cost as they are considered to be a reorganization of entities under common control. Adjustments included in the pro forma combined financial statements related to our separation and distribution agreement are as follows:

In June 2011, Williams contributed to our capital all notes payable to Williams owed by the combined entities and, as a result, as of July 1, 2011, we have and will receive our investment in these certain subsidiaries without any debt to Williams. The unaudited pro forma combined statement of operations reflects the elimination of $95 million and $119 million of affiliate interest expense associated with these notes for the nine months ended September 30, 2011 and the year ended December 31, 2010, respectively, that is replaced by the interest incurred on the new senior unsecured notes.

The indemnifications included in the separation and distribution agreement result in the addition of a $47 million non-current liability as of September 30, 2011, which represents the net asset (net of related liabilities) we have recorded related to Williams former power business matters. We will be required to pay Williams for any net cash received upon ultimate resolution of these matters. For additional information regarding these indemnifications and the Williams former power business matters, see Arrangements Between Williams and Our Company and Note 11 of Notes to Combined Financial Statements, respectively.

(b) Reflects the split of the outstanding shares of our common stock, all of which are owned by Williams, into million shares of our common stock.

Concurrent Financing Transactions

(c) Reflects the receipt of approximately $1.5 billion from our expected offering of the senior unsecured notes, after deducting the discounts of the initial purchasers of these notes and other issuance costs totaling approximately $21 million. These costs will be amortized to interest expense over the respective terms of the notes.

(d) Reflects the distribution of approximately $1,697 million to Williams from the combined net proceeds of approximately $718 million from this offering and approximately $979 million from the expected offering of $1.5 billion in senior unsecured notes discussed in adjustment (c) less our retention of $500 million.

(e) Reflects total interest expense for our $1.5 billion expected offering of the notes discussed in adjustment (c) at an assumed average interest rate of % and our new $1.5 billion senior unsecured revolving credit facility. The amount is comprised of:

interest expense on the notes;

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WPX Energy

Notes to Pro Forma Combined Financial Statements (Continued)

amortized debt issuance costs related to our debt; and

commitment fees and amortized costs related to our new credit facility.

No borrowings under the revolving credit facility are assumed for any period presented. Actual interest expense we incur in future periods may be higher or lower depending on the final terms of the senior unsecured notes and our actual utilization of the revolving credit facility. An increase in the average interest rate applicable to the senior unsecured notes of one-eighth of one percent (0.125%) would result in additional interest expense of approximately $ million and $ million for the year ended December 31, 2010 and the nine months ended September 30, 2011, respectively.

We have certain contractual obligations, primarily interstate transportation agreements, which contain collateral support requirements based on our credit ratings. Because Williams has an investment grade credit rating and guaranteed these contracts, we have not historically been required to provide collateral support. After the completion of this offering, Williams has informed us that it expects it will obtain releases of the guarantees. Depending on our credit rating, we anticipate issuing letters of credit under our Credit Facility of $285 million to satisfy the provisions of these contracts but the amount could be up to $500 million. No pro forma adjustment has been made for additional interest expense associated with our anticipated issuance of these letters of credit as an estimate of such expense is not objectively determinable until our initial credit rating has been established.

Offering Transactions

(f) Reflects the receipt of approximately $ million from the sale of shares of our common stock offered by us at an assumed initial public offering price of $ per share, net of $47 million of estimated incremental underwriter discounts and commissions and offering expenses.

Other Adjustments

(g) Reflects the adjustment of the provision (benefit) for income taxes for the adjustments made to income (loss) before income taxes at an estimated statutory rate of approximately 36%.

Note 3. Earnings per Share

Pro forma basic and diluted income (loss) from continuing operations per share was calculated by dividing the pro forma income (loss) from continuing operations by the assumed common shares outstanding, reflecting common shares owned by Williams after the stock split and common shares held by purchasers in this offering. All shares were assumed to have been outstanding since January 1, 2010. Basic and diluted pro forma income (loss) from continuing operations per share are equivalent as there are no dilutive shares or potentially dilutive items at the closing of the initial public offering.

WPX Energy
(Note 1)

Condensed Combined Statement of Operations
(Unaudited)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Dollars in millions)	
Revenues:		
Oil and gas sales, including affiliate	$ 1,877	$ 1,660
Gas management, including affiliate	1,092	1,357
Hedge ineffectiveness and mark to market gains and losses	20	25
Other	7	32
Total revenues	2,996	3,074
Costs and expenses:		
Lease and facility operating, including affiliate	218	207
Gathering, processing and transportation, including affiliate	372	216
Taxes other than income	109	109
Gas management (including charges for unutilized pipeline capacity)	1,122	1,385
Exploration	107	45
Depreciation, depletion and amortization	703	655
Impairment of producing properties and costs of acquired unproved reserves		678
Goodwill impairment		1,003
General and administrative, including affiliate	208	183
Other net	4	(6)
Total costs and expenses	2,843	4,475
Operating income (loss)	153	(1,401)
Interest expense, including affiliate	(97)	(88)
Interest capitalized	8	12
Investment income and other	19	15
Income (loss) from continuing operations before income taxes	83	(1,462)
Provision (benefit) for income taxes	29	(167)
Income (loss) from continuing operations	54	(1,295)
Loss from discontinued operations	(11)	(2)
Net income (loss)	43	(1,297)
Less: Net income attributable to noncontrolling interests	7	6

Net income (loss) attributable to WPX Energy	$ 36	$ (1,303)
Supplemental pro forma combined basic loss per common share (Note 2)		
Supplemental pro forma combined diluted loss per common share (Note 2)		

See accompanying notes.

WPX Energy
(Note 1)

Condensed Combined Balance Sheet
(Unaudited)

	Supplemental Pro Forma September 30, 2011 (Note 2)	September 30, 2011	December 31, 2010
	(Dollars in millions)		
Assets			
Current assets:			
Cash and cash equivalents	$ 50	$ 50	$ 37
Accounts receivable:			
Trade, net of allowance for doubtful accounts of $16 at September 30, 2011 and December 31, 2010	444	444	362
Affiliate	41	41	60
Derivative assets	388	388	400
Inventories	82	82	77
Other	65	65	22
Total current assets	1,070	1,070	958
Investments	119	119	105
Properties and equipment (successful efforts method of accounting)	13,485	13,485	12,564
Less accumulated depreciation, depletion and amortization	(4,756)	(4,756)	(4,115)
Properties and equipment, net	8,729	8,729	8,449
Derivative assets	118	118	173
Other noncurrent assets	105	105	161
Total assets	$ 10,141	$ 10,141	$ 9,846
Liabilities and Equity			
Current liabilities:			
Accounts payable:			
Trade	$ 536	$ 536	$ 451
Affiliates	99	99	64
Accrued and other current liabilities	171	171	158
Deferred income taxes	93	93	87
Notes payable to Williams			2,261
Accrued distribution to Williams	1,697		

Derivative liabilities		107		107		146
Total current liabilities		2,703		1,006		3,167
Deferred income taxes		1,656		1,656		1,629
Derivative liabilities		73		73		143
Asset retirement obligations		296		296		282
Other noncurrent liabilities		103		103		125
Contingent liabilities and commitments (Note 8)						
Equity:						
Owner s net equity:						
Owner s net investment		6,729		6,729		4,260
Accrued distribution to Williams		(1,697)				
Accumulated other comprehensive income		200		200		168
Total owner s net equity		5,232		6,929		4,428
Noncontrolling interests in combined subsidiaries		78		78		72
Total equity		5,310		7,007		4,500
Total liabilities and equity	$	10,141	$	10,141	$	9,846

See accompanying notes.

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WPX Energy
(Note 1)

Condensed Combined Statement of Equity
(Unaudited)

	Nine Months Ended September 30,					
	2011			2010		
	Owner s Net Equity	Noncontrolling Interests*	Total	Owner s Net Equity	Noncontrolling Interests*	Total
	(Millions)					
Beginning balance	$ 4,428	$ 72	$ 4,500	$ 5,341	$ 64	$ 5,405
Comprehensive income (loss):						
Net income	36	7	43	(1,303)	6	(1,297)
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	33		33	187		187
Total comprehensive income (loss)	69	7	76	(1,116)	6	(1,110)
Contribution of notes payable from Williams	2,420		2,420			
Dividends to noncontrolling interests		(1)	(1)		(1)	(1)
Net transfers with Williams	12		12	50		50
Ending balance	$ 6,929	$ 78	$ 7,007	$ 4,275	$ 69	$ 4,344

* Represents the 31 percent interest in Apco Oil and Gas International Inc. owned by others.

See accompanying notes.

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WPX Energy
(Note 1)

Condensed Combined Statement of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2011	2010
	(Dollars in millions)	
Operating Activities:		
Net income	$ 43	$ (1,297)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	704	661
Deferred income taxes provision (benefit)	(6)	(173)
Provision for impairment of goodwill and properties and equipment (including certain exploration expenses)	120	1,715
Gain on sales of other assets		(13)
Cash provided (used) by operating assets and liabilities:		
Accounts receivable and payable affiliate	49	30
Accounts receivable trade	(88)	59
Inventories	(5)	(25)
Margin deposits and customer margin deposits payable	(25)	5
Other current assets	(10)	10
Accounts payable trade	78	(61)
Accrued and other current liabilities	31	(55)
Changes in current and noncurrent derivative assets and liabilities	7	(38)
Other, including changes in noncurrent assets and liabilities	(10)	34
Net cash provided by operating activities	888	852
Investing Activities:		
Capital expenditures*	(1,088)	(1,460)
Proceeds from sales of assets	17	32
Purchases of investments	(8)	(6)
Other net	23	1
Net cash used by investing activities	(1,056)	(1,433)
Financing Activities:		
Net changes in notes payable to parent	159	532
Net changes in owner s investment	33	52
Revolving debt facility costs	(8)	
Other	(3)	(2)
Net cash provided (used) by financing activities	181	582

Increase in cash and cash equivalents	13	1
Cash and cash equivalents at beginning of period	37	34
Cash and cash equivalents at end of period	$ 50	$ 35
* Increases to property, plant, and equipment	$ (1,095)	$ (1,477)
Changes in related accounts payable and accrued liabilities	7	17
Capital expenditures	$ (1,088)	$ (1,460)

See accompanying notes.

WPX Energy

Notes to Condensed Combined Financial Statements

(Unaudited)

Note 1. General

The combined businesses represented herein as WPX Energy (also referred to as the Company) comprise substantially all of the exploration and production operating segment of The Williams Companies, Inc. (Williams). In these notes, WPX Energy is referred to in the first person as we , us or our .

On February 16, 2011, Williams announced that its Board of Directors approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. The plan first calls for Williams to separate its exploration and production business via an initial public offering (the Offering) of up to 20 percent of its interest. As a result, WPX Energy, Inc. was formed in April 2011 to effect the separation. In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business, including its wholly-owned subsidiaries Williams Production Holdings, LLC and Williams Production Company, LLC, as well as all ongoing operations of WPX Energy Marketing LLC, formerly known as Williams Gas Marketing, Inc. In October 2011, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its 69 percent ownership interest in Apco Oil and Gas International Inc. (Apco , NASDAQ listed: APAGF). We refer to the collective contributions described herein as the Contribution .

On October 18, 2011, Williams announced that its Board of Directors approved a revised reorganization plan that calls for the complete separation of us via a tax-free spin-off of all of Williams ownership of us to Williams shareholders by year-end 2011. On October 20, 2011, we filed a Form 10 registration statement with the SEC with respect to this spin-off of our securities. The approval of the revised reorganization plan does not preclude Williams from pursuing the original plan for separation, including an initial public offering, in the event that market conditions become favorable. Williams retains the discretion to determine whether and when to complete these transactions.

WPX Energy includes natural gas development, production and gas management activities located in the Rocky Mountain (primarily Colorado, New Mexico, and Wyoming), Mid-Continent (Texas), and Appalachian regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Green River, Fort Worth, and Appalachian Basins. During 2010, we acquired a company with a significant acreage position in the Williston Basin (Bakken Shale) in North Dakota, which is primarily comprised of crude oil reserves. We also have international oil and gas interests which represented approximately two percent of combined revenues and approximately six percent of proved reserves for the year ended December 31, 2010. These international interests primarily consist of our ownership in Apco, an oil and gas exploration and production company with operations in South America.

Note 2. Basis of Presentation

Our accompanying interim condensed combined financial statements are unaudited and do not include all disclosures required in annual financial statements and therefore should be read in conjunction with the combined financial statements and notes thereto of the Company as of December 31, 2010 and 2009 and for each of the three years in the period ended December 31, 2010, included elsewhere in this registration statement. The accompanying unaudited condensed combined financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2011 and our results of operations, changes in equity, and cash flows for the nine months ended September 30, 2011 and 2010.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

condensed combined financial statements and accompanying notes. Actual results could differ from those estimates.

Discontinued operations

The accompanying condensed combined financial statements and notes reflect the results of operations and financial position of our Arkoma Basin operations as discontinued operations for all periods (See Note 3).

Unless indicated otherwise, the information in the Notes to Condensed Combined Financial Statements relates to our continuing operations.

Accounting Standards Issued But Not Yet Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-4, Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU 2011-4). ASU 2011-4 primarily eliminates the differences in fair value measurement principles between the FASB and International Accounting Standards Board. It clarifies existing guidance, changes certain fair value measurements and requires expanded disclosure primarily related to Level 3 measurements and transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-4 is effective on a prospective basis for interim and annual periods beginning after December 15, 2011. We are assessing the application of this Update to our combined financial statements.

In June 2011, the FASB issued Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220) Presentation of Comprehensive Income (ASU 2011-5). ASU 2011-5 requires presentation of net income and other comprehensive income either in a single continuous statement or in two separate, but consecutive, statements. The Update requires separate presentation in both net income and other comprehensive income of reclassification adjustments for items that are reclassified from other comprehensive income to net income. The new guidance does not change the items reported in other comprehensive income, nor affect how earnings per share is calculated and presented. We currently report net income in the combined statement of operations and report other comprehensive income in the combined statement of equity. The standard is effective beginning the first quarter of 2012, with a retrospective application to prior periods. We plan to apply the new presentation beginning in 2012.

Unaudited Supplemental pro forma balance sheet and pro forma combined loss per share

Inasmuch as our planned separation from Williams requires us to make a distribution from the Offering proceeds, which is not reflected in the historical September 30, 2011 balance sheet, and since the distribution is in excess of our combined estimated Offering proceeds and last twelve months earnings, we have presented a supplemental unaudited pro forma balance sheet as of September 30, 2011, and also given effect to this via supplemental pro forma combined earnings/loss per share. For pro forma purposes, this distribution is considered a dividend to Williams.

Basic and diluted pro forma combined loss per share for the nine months ended September 30, 2011 were calculated by assuming common shares outstanding, reflecting common shares owned by Williams after the stock split and common shares held by the purchasers in the Offering. Additionally, for purposes of calculating basic and diluted pro forma combined loss per share, our historical net income was decreased by $27 million to reflect incremental interest expense (net of tax) related to the portion of the $1,697 million distribution that exceeds the proceeds from the Offering and our earnings for the previous twelve months.

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)	
Revenues	$ 10	$ 13
Loss from discontinued operations before impairment and income taxes	$ (1)	$ (3)
Impairment of producing properties	(16)	
Benefit for income taxes	6	1
Loss from discontinued operations	$ (11)	$ (2)

Impairments in 2011 reflect write-downs to an estimate of fair value less costs to sell the assets of our Arkoma Basin operations that were classified as held for sale as of September 30, 2011. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, was based on a probability-weighted discounted cash flow analysis that included offers we have received on the assets and internal cash flow models.

The assets of our discontinued operations comprise significantly less than one percent of our total combined assets as of September 30, 2011, and December 31, 2010, and are reported within other current assets and other noncurrent assets, respectively, on our Condensed Combined Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

Note 4. Related Party Transactions

Transactions with Williams and Other Affiliated Entities

Below is a summary of the related party transactions for the nine months ended September 30, 2011 and 2010:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)	
Oil and gas sales revenues sales of NGLs to WPZ	$ 232	$ 186
	402	386

Gas management revenues sales of natural gas for fuel and shrink to WPZ and another Williams subsidiary		
Lease and facility operating expenses from Williams-direct employee salary and benefit costs	15	19
Gathering, processing and transportation expense from WPZ:		
Gathering and processing	236	95
Transportation	34	16
General and administrative from Williams:		
Direct employee salary and benefit costs	83	74
Charges for general and administrative services	45	43
Allocated general corporate costs	47	47
Other	12	10
Interest expense on notes payable to Williams	95	85

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

Daily cash activity from our domestic operations was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011, at which time the notes were cancelled by Williams. The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in owner s net investment.

As previously discussed, our domestic operations were contributed to WPX Energy, Inc. on July 1, 2011. On June 30, 2011, certain entities that were contributed to us on July 1, 2011 withdrew from Williams benefit plans and terminated their personnel services agreements with Williams payroll companies. Simultaneously, two new administrative services entities owned and controlled by Williams executed new personnel services agreements with the payroll companies and joined the Williams plans as participants. The effect of these transactions is that none of the companies contributed to WPX Energy has any employees as of September 30, 2011. The services entities employ all personnel that provide services to WPX Energy and remain owned and controlled 100% by Williams.

In addition, the current amount due to or from affiliates consists of normal course receivables and payables resulting from the sale of products to and cost of gathering services provided by WPZ. Below is a summary of these payables and receivables which are settled monthly:

	September 30, 2011	December 31, 2010
	(Millions)	
Current:		
Accounts receivable:		
Due from WPZ and another Williams subsidiary	$ 41	$ 60
Accounts payable:		
Due to WPZ	$ 25	$ 12
Due to Williams for cash overdraft	63	38
Due to Williams for accrued payroll and benefits	11	14
	$ 99	$ 64
Current derivative asset with WPZ	$ 7	$
Current derivative liability with WPZ	$ 4	$

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

Note 5. Asset Sales, Impairments and Exploration Expenses

The following table presents a summary of significant gains or losses reflected in impairment of producing properties and costs of acquired unproved reserves, goodwill impairment and other net within costs and expenses:

	Nine Months Ended September 30, 2011	2010
	(Millions)	
Goodwill impairment		$ 1,003
Impairment of producing properties and costs of acquired unproved reserves*		678
Gain on sales of other assets		(13)

* Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.

As a result of significant declines in forward natural gas prices during 2010, we performed an interim impairment assessment in 2010 of our capitalized costs related to goodwill and domestic producing properties. As a result of these assessments, we recorded an impairment of goodwill, as noted above, and impairments of our capitalized costs of certain natural gas producing properties in the Barnett Shale of $503 million and capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million (see Note 9).

Our impairment analyses included an assessment of undiscounted (except for the costs of acquired unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities, and natural gas reserve quantities.

In July 2010, we sold a portion of our gathering and processing facilities in the Piceance Basin to a third party for cash proceeds of $30 million resulting in a gain of $12 million.

The following presents a summary of exploration expenses:

	Nine Months Ended September 30, 2011	2010
	(Millions)	
Geologic and geophysical costs	$ 4	$ 15
Dry hole costs	13	15
Unproved leasehold property impairment, amortization and expiration	90	15

Total exploration expense	$	107	$	45

Dry hole costs in 2011 reflect an $11 million dry hole expense in connection with a Marcellus Shale well in Columbia County, Pennsylvania, while 2010 reflects dry hole expense associated with our Paradox basin.

Unproved leasehold impairment, amortization and expiration in 2011 includes a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage that we do not plan to develop.

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

Note 6. Inventories

	September 30, 2011	December 31, 2010
	(Millions)	
Natural gas in underground storage	$ 38	$ 31
Materials, supplies and other	44	46
Total inventories	$ 82	$ 77

Note 7. Provision (Benefit) for Income Taxes

The provision (benefit) for income taxes includes:

	Nine Months Ended September 30, 2011	2010
	(Millions)	
Current:		
Federal	$ 19	$ (2)
State	2	1
Foreign	8	7
	29	6
Deferred:		
Federal	1	(163)
State	(1)	(10)
Foreign		
		(173)
Total provision (benefit)	$ 29	$ (167)

The effective income tax rate of the total provision for the nine months ended September 30, 2011 approximates the federal statutory rate as taxes on foreign operations partially offset the effect of state income taxes.

The effective income tax rate of the total benefit for the nine months ended September 30, 2010, is less than the federal statutory rate due primarily to the non-deductible goodwill impairment.

During the next twelve months, we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of our unrecognized tax benefit.

Note 8. Contingent Liabilities and Commitments

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify as a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class members for class certification, reserved two claims for court resolution, resolved all other class claims relating to past calculation of royalty and overriding

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

royalty payments, and established certain rules to govern future royalty and overriding royalty payments. This settlement resolved all claims relating to past withholding for ad valorem tax payments and established a procedure for refunds of any such excess withholding in the future. The first reserved claim is whether we are entitled to deduct in our calculation of royalty payments a portion of the costs we incur beyond the tailgates of the treating or processing plants for mainline pipeline transportation. We received a favorable ruling on our motion for summary judgment on the first reserved claim. Plaintiffs appealed that ruling and the Colorado Court of Appeals found in our favor in April 2011. In June 2011, Plaintiffs filed a Petition for Certiorari with the Colorado Supreme Court. We anticipate that Court will issue a decision on whether to grant further review later in 2011 or early in 2012. The second reserved claim relates to whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are thus entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate trial on the second reserved claim following resolution of the first reserved claim. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims. However, it is reasonably possible that the ultimate resolution of this item could result in a future charge that may be material to our results of operations.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5, 2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states, but such guidelines are expected in the future. However, the timing of receipt of the necessary guidelines is uncertain. In addition, these interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and will vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. From January 2004 through December 2010, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $55 million. Correspondence in 2009 with the ONRR s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions which we believe have been consistent with the requirements. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments and the effect could be material to our results of operations.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that Williams has underpaid royalties due per the oil and gas leases with the State of New Mexico. In August 2011, the parties agreed to stay this matter pending the New Mexico Supreme Court s resolution of a similar matter involving a different producer.

Environmental matters

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

for ground level ozone, and one hour nitrogen dioxide emission limits. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matters related to Williams former power business

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of natural gas-related information to trade publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. On January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. We expect that the Colorado plaintiffs will appeal now that the court s order became final on July 18, 2011.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. On July 22, 2011, the plaintiffs filed their notice of appeal with the Nevada district court. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At September 30, 2011, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters, and environmental matters and safety matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. As of September 30, 2011 and December 31, 2010, the Company had accrued approximately $23 million and $21 million, respectively, for loss contingencies associated with royalty litigation, reporting of natural gas information to trade publications and other contingencies. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

Commitments

As part of managing our commodity price risk, we utilize contracted pipeline capacity (including capacity on affiliates systems, resulting in a total of $412 million for all years) to move our natural gas production and third party gas purchases to other locations in an attempt to obtain more favorable pricing differentials. Our commitments under these contracts as of September 30, 2011 are as follows:

	(Millions)
Remainder of 2011	$ 53
2012	216
2013	211
2014	177
2015	166
Thereafter	633
Total	$ 1,456

We also have certain commitments to an equity investee and others, primarily for natural gas gathering and treating services and well completion services, which total $826 million over approximately seven years.

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu per day of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. This obligation expires in 2014.

In connection with a gathering agreement entered into by WPZ with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu per day of natural gas at Transco Station 515 (Marcellus Basin) at market prices from the same third party. Purchases under the 12-year contract are expected to begin

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

in the fourth quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Future minimum annual rentals under noncancelable operating leases as of September 30, 2011, are payable as follows:

	(Millions)
Remainder of 2011	$ 9
2012	71
2013	74
2014	65
2015	35
Thereafter	41
Total	$ 295

Note 9. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(Millions)				(Millions)		
Energy derivative assets	$ 52	$ 450	$ 4	$ 506	$ 97	$ 474	$ 2	$ 573
Energy derivative liabilities	$ 44	$ 133	$ 3	$ 180	$ 78	$ 210	$ 1	$ 289

Energy derivatives include commodity based exchange-traded contracts and over the counter (OTC) contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the net fair value of our derivatives portfolio expiring in the next 15 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at September 30, 2011, consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers between Level 1 and Level 2 occurred during the period ended September 30, 2011 or 2010.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Nine Months Ended September 30,	
	2011	2010
	(Millions)	
Beginning balance	$ 1	$ 1
Realized and unrealized gains included in income from continuing operations	12	2
Settlements	(9)	(1)
Transfers into Level 3		
Transfers out of Level 3	(3)	
Ending balance	$ 1	$ 2
Unrealized gains included in income from continuing operations relating to instruments still held at September 30	$ 1	$ 1

Realized and unrealized gains included in income from continuing operations for the above periods are reported in revenues in our Condensed Combined Statement of Operations.

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

Fair Value Measurements Using:

	Total Losses for the Nine Months Ended September 30, 2011		2010
	(Millions)		
Impairments:			
Goodwill (see Note 5)	$	$	1,003(a)
Producing properties and costs of acquired unproved reserves (see Note 5)			678(b)
	$	$	1,681

(a) Due to a significant decline in forward natural gas prices across all future production periods during 2010, we determined that we had a trigger event and thus performed an interim impairment assessment of the approximate $1 billion of goodwill related to our domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after- tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined that the implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

(b) As of September 30, 2010, we also believed we had a trigger event as a result of significant declines in forward natural gas prices and therefore, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows.

Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $678 million impairment charge in the third-quarter 2010 as further described below. Fair value measured for these properties at September 30, 2010, was estimated to be approximately $320 million.

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

$503 million of the impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

$175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent.

Note 10. Financial Instruments, Derivatives, Guarantees, and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

<u>*Cash and cash equivalents and restricted cash*</u>: The carrying amounts reported in the Condensed Combined Balance Sheet approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

<u>*Other*</u>: Includes margin deposits and customer margin deposits payable for which the amounts reported in the Condensed Combined Balance Sheet approximate fair value.

<u>*Energy derivatives*</u>: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Condensed Combined Balance Sheet. See Note 9 for a discussion of the valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments were as follows:

	September 30, 2011		December 31, 2010	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
	(Millions)			
Cash and cash equivalents	$ 50	$ 50	$ 37	$ 37
Restricted cash	$ 29	$ 29	$ 24	$ 24
Other	$	$	$ (25)	$ (25)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 316	$ 316	$ 266	$ 266
Other energy derivatives	$ 10	$ 10	$ 18	$ 18

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and crude oil attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

We produce, buy, and sell natural gas and crude oil at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas and crude oil market prices, we enter into natural gas and crude oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and crude oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Those agreements and contracts designated as cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar.

The following table sets forth the derivative volumes designated as hedges of production volumes as of September 30, 2011:

Commodity	Period	Contract Type	Location	Notional Volume (BBtu)	Weighted Average Price ($/MMBtu)
Natural Gas	Oct-Dec 2011	Costless Collar	Rockies	4,140	$5.30 - $7.10
Natural Gas	Oct-Dec 2011	Costless Collar	San Juan	8,280	$5.27 - $7.06
Natural Gas	Oct-Dec 2011	Costless Collar	MidCon	7,360	$5.10 - $7.00
Natural Gas	Oct-Dec 2011	Costless Collar	SoCal	2,760	$5.83 - $7.56
Natural Gas	Oct-Dec 2011	Costless Collar	North East	2,760	$6.50 - $8.14
Natural Gas	Oct-Dec 2011	Location Swaps	Rockies	8,740	$5.31
Natural Gas	Oct-Dec 2011	Location Swaps	San Juan	10,120	$5.10
Natural Gas	Oct-Dec 2011	Location Swaps	MidCon	2,300	$5.05
Natural Gas	Oct-Dec 2011	Location Swaps	SoCal	3,680	$4.95
Natural Gas	Oct-Dec 2011	Location Swaps	North East	11,490	$5.48
Natural Gas	2012	Location Swaps	Rockies	49,410	$4.76
Natural Gas	2012	Location Swaps	San Juan	40,260	$4.94
Natural Gas	2012	Location Swaps	MidCon	32,025	$4.76
Natural Gas	2012	Location Swaps	SoCal	11,895	$5.14
Natural Gas	2012	Location Swaps	North East	52,460	$5.58
Natural Gas	2013	Location Swaps	North East	1,800	$6.48
Commodity	**Period**	**Contract Type**	**Location**	**Notional Volume (MBbl)**	**Weighted Average Price ($/Bbl)**
Crude Oil	Oct-Dec 2011	Business Day Avg Swaps	WTI	414	$96.56
Crude Oil	2012	Business Day Avg Swaps	WTI	2,624	$97.32

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Hedges for transportation contracts are designated as cash flow hedges and are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Hedges for storage contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and

WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

providing services to third parties and affiliated entities. These legacy natural gas contracts include substantially offsetting positions and have an insignificant net impact on earnings.

The following table depicts the notional amounts of the net long (short) positions which we did not designate as hedges of our production in our commodity derivatives portfolio as of September 30, 2011. Natural gas is presented in millions of British Thermal Units (MMBtu). All of the Central hub risk realizes by March 31, 2012 and 100% of the basis risk realizes by 2013. The net index position includes contracts for the future sale of physical natural gas related to our production. Offsetting these sales are contracts for the future production of physical natural gas related to WPZ s natural gas shrink requirements. These contracts result in minimal commodity price risk exposure and have a value of less than $1 million at September 30, 2011.

Derivative Notional Volumes	Unit of Measure	Central Hub Risk(a)(d)	Basis Risk(b)	Index Risk(c)
Not Designated as Hedging Instruments				
Risk Management	MMBtu	(11,400,829)	(6,733,329)	(81,599,245)
Other	MMBtu		(6,110,000)	

(a) includes physical and financial derivative transactions that settle against the Henry Hub price;

(b) includes financial derivative transactions priced off the difference in value between the Central Hub and another specific delivery point;

(c) includes physical derivative transactions at an unknown future price, including purchases of 64,204,250 MMBtu primarily on behalf of WPZ and sales of 145,803,495 MMBtu.

(d) includes financial derivatives entered into with WPZ to reduce its exposure to decreases in its revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices. These contracts are offset by 3rd party agreements.

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Condensed Combined Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	September 30, 2011		December 31, 2010	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 331	$ 15	$ 288	$ 22
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	130	129	186	187
All other	45	36	99	80
Total derivatives not designated as hedging instruments	175	165	285	267
Total derivatives	$ 506	$ 180	$ 573	$ 289

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in accumulated other comprehensive income (AOCI) or revenues.

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Classification
	(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$ 270	$ 530	AOCI
Net gain reclassified from AOCI into income (effective portion)	$ 219	$ 235	Revenues
Gain recognized in income (ineffective portion)	$	$ 4	Revenues

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)	
Gas management revenues	$ 19	$ 39
Gas management expenses		18
Net gain	$ 19	$ 21

The cash flow impact of our derivative activities is presented in the Condensed Combined Statement of Cash Flows as *changes in current and noncurrent derivative assets and liabilities*.

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, we have an unsecured credit agreement with certain banks related to hedging activities. We are not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of our domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money position on hedges entered into under the credit agreement.

As of September 30, 2011, we had collateral totaling $4 million posted to derivative counterparties to support the aggregate fair value of our net $21 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2010, we had collateral totaling $8 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $36 million, which included a reduction of less than $1 million to our liability

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $17 million and $29 million at September 30, 2011 and December 31, 2010, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of September 30, 2011, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at September 30, 2011, $171 million of net gains (net of income tax provision of $101 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of September 30, 2011. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Concentration of Credit Risk

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties. The gross credit exposure from our derivative contracts as of September 30, 2011, is summarized as follows:

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities and integrated oil and gas companies	$ 10	$ 10
Energy marketers and traders		75
Financial institutions	421	421
	$ 431	506

Credit reserves

Gross credit exposure from derivatives	$ 506

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

under derivative contracts. The net credit exposure from our derivatives as of September 30, 2011, excluding collateral support discussed below, is summarized as follows:

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities and integrated oil and gas companies	$ 5	$ 5
Energy marketers and traders		1
Financial institutions	342	342
	$ 347	348
Credit reserves		
Net credit exposure from derivatives		$ 348

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade.

Our seven largest net counterparty positions represent approximately 94 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are counterparty positions, representing 89 percent of our net credit exposure from derivatives, associated our hedging facility. Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

At September 30, 2011, the designated collateral agent is not required to hold any collateral support on our behalf under our hedging facility. We hold collateral support, which may include cash or letters of credit, of $5 million related to our other derivative positions.

Note 11. Revolving Credit Agreement

On June 3, 2011, WPX Energy, Inc., as borrower, entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility Agreement), together with the lenders named therein, and Citibank N.A. (Citi), as administrative agent and swingline lender. Under the terms of the Credit Facility Agreement and subject to certain requirements, WPX Energy, Inc. may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. Borrowings under the Credit Facility Agreement may be used for working capital, acquisitions, capital expenditures and other general corporate purposes.

Under the Credit Facility Agreement, WPX Energy, Inc. may also obtain same day funds by requesting a swingline loan of up to an amount of $125 million from the swingline lender. Interest on swingline loans will be payable at a fluctuating base rate equal to Citi s adjusted base rate plus the applicable margin.

The Credit Facility Agreement will not be effective until the date on which certain conditions listed in the agreement (including, among others, the completion of the initial public offering of WPX Energy, Inc.) have been met or waived; provided that the effective date must be on or before November 30, 2011 or such later date as may be agreed to by WPX Energy, Inc. and the lenders. If the effective date has not occurred by November 30, 2011, the Credit Facility Agreement will automatically terminate unless otherwise extended by WPX Energy, Inc. and the lenders. WPX Energy, Inc. is in the process of seeking an amendment to the Credit Facility Agreement that will eliminate any condition to effectiveness of the Credit Facility Agreement relating to the completion of the initial public offering of WPX Energy, Inc. Costs totalling $8 million associated with the

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WPX Energy

Notes to Condensed Combined Financial Statements (Continued)

establishment of this facility have been deferred in other assets and will be amortized over the life of the agreement.

Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at the option of WPX Energy, Inc.: (1) a fluctuating base rate equal to Citi s adjusted base rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) Citi s publicly announced base rate, and (iii) one-month LIBOR plus 1.0 percent. WPX Energy, Inc. will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility Agreement. The applicable margin and the commitment fee will be determined by reference to a pricing schedule based on WPX Energy, Inc. s senior unsecured debt ratings.

Under the Credit Facility Agreement, prior to the occurrence of the Investment Grade Date (as defined below), WPX Energy, Inc. will be required to maintain a ratio of PV to debt (each as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. PV is determined as of the end of each fiscal year and reflects the present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves (with a limitation of no more than 35% of proved undeveloped reserves), based on lender projected commodity price assumptions and after giving effect to hedge arrangements. Also, for WPX Energy, Inc. and its consolidated subsidiaries, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. Each of the above ratios will be tested beginning June 30, 2011 at the end of each fiscal quarter. Investment Grade Date means the first date on which WPX Energy, Inc. s long-term senior unsecured debt ratings are BBB- or better by S&P or Baa3 or better by Moody s (without negative outlook or negative watch), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody s.

The Credit Facility Agreement contains customary representations and warranties and affirmative, negative and financial covenants which were made only for the purposes of the Credit Facility Agreement and as of the specific date (or dates) set forth therein, and may be subject to certain limitations as agreed upon by the contracting parties. The covenants limit, among other things, the ability of WPX Energy, Inc. s subsidiaries to incur indebtedness, WPX Energy, Inc. and its material subsidiaries from granting certain liens supporting indebtedness, making investments, loans or advances and entering into certain hedging agreements, WPX Energy, Inc. s ability to merge or consolidate with any person or sell all or substantially all of its assets to any person, enter into certain affiliate transactions, make certain distributions during the continuation of an event of default and allow material changes in the nature of its business. In addition, the representations, warranties and covenants contained in the Credit Facility Agreement may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors. Investors are not third-party beneficiaries of the Credit Facility Agreement and should not rely on the representations, warranties and covenants contained therein, or any descriptions thereof, as characterizations of the actual state of facts or conditions of WPX Energy, Inc.

The Credit Facility Agreement includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to a borrower occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of the loans of the defaulting borrower under the Credit Facility Agreement and exercise other rights and remedies.

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Report of Independent Registered Public Accounting Firm

The Board of Directors
WPX Energy, Inc.

We have audited the accompanying combined balance sheet of WPX Energy (see Note 1) as of December 31, 2010 and 2009, and the related combined statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed at Item 16(b). These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule 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. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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 combined financial position of WPX Energy at December 31, 2010 and 2009, and the combined 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. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 5 to the combined financial statements, beginning in 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
April 29, 2011, except as it relates to the matter discussed
in the first paragraph of Basis of Presentation Discontinued
Operations as set forth in Note 1, and the matter
discussed in Note 2, as to which the date is
June 21, 2011, and except as it relates to the matter
discussed in the second paragraph of Description of
Business as set forth in Note 1, as to which the date is
July 18, 2011

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WPX Energy
(Note 1)

Combined Statement of Operations

	Years Ended December 31, 2010	2009	2008
	(Dollars in millions)		
Revenues:			
Oil and gas sales, including affiliate	$ 2,225	$ 2,168	$ 2,882
Gas management, including affiliate	1,742	1,456	3,241
Hedge ineffectiveness and mark to market gains and losses	27	18	29
Other	40	39	32
Total revenues	4,034	3,681	6,184
Costs and expenses:			
Lease and facility operating, including affiliate	286	263	272
Gathering, processing and transportation, including affiliate	326	273	229
Taxes other than income	125	93	254
Gas management (including charges for unutilized pipeline capacity)	1,771	1,495	3,248
Exploration	73	54	37
Depreciation, depletion and amortization	875	887	738
Impairment of producing properties and costs of acquired unproved reserves	678	15	
Goodwill impairment	1,003		
General and administrative, including affiliate	253	251	247
Gain on sale of contractual right to international production payment			(148)
Other net	(19)	33	6
Total costs and expenses	5,371	3,364	4,883
Operating income (loss)	(1,337)	317	1,301
Interest expense, including affiliate	(124)	(100)	(74)
Interest capitalized	16	18	20
Investment income and other	21	8	22
Income (loss) from continuing operations before income taxes	(1,424)	243	1,269
Provision (benefit) for income taxes	(150)	94	452
Income (loss) from continuing operations	(1,274)	149	817
Loss from discontinued operations	(8)	(7)	(87)
Net income (loss)	(1,282)	142	730
Less: Net income attributable to noncontrolling interests	8	6	8
Net income (loss) attributable to WPX Energy	$ (1,290)	$ 136	$ 722

$

Unaudited Supplemental pro forma combined basic loss per common share (Note 1)	
Unaudited Supplemental pro forma combined diluted loss per common share (Note 1)	$

See accompanying notes.

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WPX Energy
(Note 1)

Combined Balance Sheet

	December 31, 2010	December 31, 2009
	(Dollars in millions)	
Assets		
Current assets:		
Cash and cash equivalents	$ 37	$ 34
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $16 and $19 as of December 31, 2010 and 2009, respectively	362	359
Affiliate	60	54
Derivative assets	400	650
Inventories	77	61
Other	22	41
Total current assets	958	1,199
Investments	105	95
Properties and equipment, net (successful efforts method of accounting)	8,449	7,662
Derivative assets	173	444
Goodwill, net		1,003
Other noncurrent assets	161	150
Total assets	$ 9,846	$ 10,553
Liabilities and Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 451	$ 462
Affiliates	64	37
Accrued and other current liabilities	158	231
Deferred income taxes	87	28
Notes payable to Williams	2,261	1,216
Derivative liabilities	146	578
Total current liabilities	3,167	2,552
Deferred income taxes	1,629	1,841
Derivative liabilities	143	428
Asset retirement obligations	282	235
Other noncurrent liabilities	125	92
Contingent liabilities and commitments *(Note 11)*		
Equity:		
Owner s net equity:		
Owner s net investment	4,260	5,269

Accumulated other comprehensive income	168	72
Total owner s net equity	4,428	5,341
Noncontrolling interests in combined subsidiaries	72	64
Total equity	4,500	5,405
Total liabilities and equity	$ 9,846	$ 10,553

See accompanying notes.

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WPX Energy
(Note 1)

Combined Statement of Equity

	Owner s Net Investment	Accumulated Other Comprehensive Income (Loss)*	Total Owner s Net Equity	Noncontrolling Interest**	Total
	(Dollars in millions)				
Balance at December 31, 2007	$ 4,462	$ (161)	$ 4,301	$ 55	$ 4,356
Comprehensive income:					
Net income	722		722	8	730
Other comprehensive income:					
Change in fair value of cash flow hedges (net of $260 of income tax)		454	454		454
Net reclassifications into earnings of net cash flow hedge losses (net of $3 income tax benefit)		5	5		5
Total other comprehensive income					459
Total comprehensive income					1,189
Net transfers with Williams	(35)		(35)		(35)
Dividends to noncontrolling interests				(4)	(4)
Balance at December 31, 2008	5,149	298	5,447	59	5,506
Comprehensive income:					
Net income	136		136	6	142
Other comprehensive income:					
Change in fair value of net cash flow hedges (net of $97 of income tax)		169	169		169
Net reclassifications into earnings of cash flow hedge gain (net of $226 income tax provision)		(395)	(395)		(395)
Total other comprehensive loss					(226)
Total comprehensive loss					(84)
Net transfers with Williams	(16)		(16)		(16)
Dividends to noncontrolling interests				(1)	(1)

Balance at December 31, 2009	5,269	72	5,341	64	5,405
Comprehensive income:					
Net loss	(1,290)		(1,290)	8	(1,282)
Other comprehensive income:					
Change in fair value of net cash flow hedges (net of $184 of income tax)		321	321		321
Net reclassifications into earnings of cash flow hedge gains (net of $129 income tax provision)		(225)	(225)		(225)
Total other comprehensive income					96
Total comprehensive loss					(1,186)
Cash proceeds in excess of historical book value related to assets sold to an affiliate	244		244		244
Net transfers with Williams	37		37		37
Dividends to noncontrolling interests					
Balance at December 31, 2010	$ 4,260	$ 168	$ 4,428	$ 72	$ 4,500

* Accumulated other Comprehensive income (loss) is comprised primarily of unrealized gains relating to natural gas hedges totaling $169 million (net of $97 million for income taxes), $74 million (net of $42 million for income taxes) and $299 million (net of $172 million for income taxes) as of December 31, 2010, 2009 and 2008, respectively.

** Represents the 31 percent interest in Apco Oil and Gas International Inc. owned by others.

See accompanying notes.

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WPX Energy
(Note 1)

Combined Statement of Cash Flows

	Years Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Operating Activities			
Net income (loss)	$ (1,282)	$ 142	$ 730
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	882	894	758
Deferred income tax provision (benefit)	(167)	106	456
Provision for impairment of goodwill and properties and equipment (including certain exploration expenses)	1,734	38	173
Provision for loss on cost-based investment		11	
Gain on sale of contractual right to international production payment			(148)
(Gain) loss on sales of other assets	(22)	1	1
Cash provided (used) by operating assets and liabilities:			
Accounts receivable and payable affiliate	21	(72)	20
Accounts receivable trade	7	103	127
Other current assets	19	(17)	(11)
Inventories	(16)	24	(32)
Margin deposits and customer margin deposit payable	(1)	4	87
Accounts payable trade	(54)	(17)	(91)
Accrued and other current liabilities	(62)	(109)	27
Changes in current and noncurrent derivative assets and liabilities	(45)	38	(119)
Other, including changes in other noncurrent assets and liabilities	42	35	31
Net cash provided by operating activities	1,056	1,181	2,009
Investing Activities			
Capital expenditures*	(1,856)	(1,434)	(2,467)
Purchase of business	(949)		
Proceeds from sale of contractual right to international production payment			148
Proceeds from sales of assets	493		72
Purchases of investments	(7)	(1)	(5)
Other	(18)		
Net cash used in investing activities	(2,337)	(1,435)	(2,252)
Financing Activities			
Net changes in notes payable to parent	1,045	270	269
Net changes in owner s net investment	241	(16)	(38)
Other	(2)	2	(6)

Net cash provided by financing activities	1,284	256	225
Net change in cash and cash equivalents	3	2	(18)
Cash and cash equivalents at beginning of period	34	32	50
Cash and cash equivalents at end of period	$ 37	$ 34	$ 32
* Increase to properties and equipment	$ (1,891)	$ (1,291)	$ (2,520)
Changes in related accounts payable	35	(143)	53
Capital expenditures	$ (1,856)	$ (1,434)	$ (2,467)

See accompanying notes.

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WPX Energy

Notes to Combined Financial Statements

1. Description of Business, Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

The combined businesses represented herein as WPX Energy (also referred to herein as the Company) comprise substantially all of the exploration and production operating segment of The Williams Companies, Inc. (Williams). In these notes, WPX Energy is at times referred to in the first person as we , us or our .

On February 16, 2011, Williams announced that its Board of Directors approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. The plan first calls for Williams to separate its exploration and production business via an initial public offering (the Offering) of up to 20 percent of its interest. As a result, WPX Energy, Inc. has been formed to effect the separation. In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business, including its wholly-owned subsidiaries Williams Production Holdings, LLC and Williams Production Company, LLC, as well as all ongoing operations of Williams Gas Marketing, Inc. Additionally, prior to the close of the Offering, Williams will contribute and transfer to the Company its investment in certain subsidiaries related to its international exploration and production business, including its 69 percent ownership interest in Apco Oil and Gas International Inc. (Apco , NASDAQ listed: APAGF). We refer to the collective contributions described herein as the Contribution .

WPX Energy includes natural gas development, production and gas management activities located in the Rocky Mountain (primarily Colorado, New Mexico, and Wyoming), Mid-Continent (Texas), and Appalachian regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Green River, Fort Worth, and Appalachian Basins. During 2010, we acquired a company with a significant acreage position in the Williston Basin (Bakken Shale) in North Dakota, which is primarily comprised of crude oil reserves. We also have international oil and gas interests which represented approximately two percent of combined revenues and approximately six percent of proved reserves for the year ended December 31, 2010. These international interests primarily consist of our ownership in Apco, an oil and gas exploration and production company with operations in South America.

Basis of Presentation

These financial statements are prepared on a combined, rather than a consolidated basis. The combined financial statements have been derived from the financial statements and accounting records of Williams using the historical results of operations and historical basis of the assets and liabilities of the Contribution to WPX Energy.

Management believes the assumptions underlying the financial statements are reasonable. However, the financial statements included herein may not necessarily reflect the Company s results of operations, financial position and cash flows in the future or what its results of operations, financial position and cash flows would have been had the Company been a stand-alone company during the periods presented. Because a direct ownership relationship did not exist among the various entities that will comprise the Company, Williams net investment in the Company, excluding notes payable to Williams, is shown as owner s net investment in lieu of stockholder s equity in the combined financial statements. Transactions between the Company and Williams which are not part of the notes payable have been identified in the Combined Statements of Equity as net transfers with Williams (see Note 4). Transactions with Williams other operating businesses, which generally settle monthly, are shown as accounts receivable-affiliate or accounts payable-affiliate (see Note 4). The accompanying combined financial statements do not reflect any changes that have occurred or will occur upon the Contribution and recapitalization of the Company, or may occur in the capitalization and operations of the Company as a result of, or after, any spin-off of the Company.

During fourth quarter 2010, the Company sold certain gathering and processing assets in Colorado s Piceance Basin (the Piceance Sale) with a net book value of $458 million to Williams Partners L.P.

WPX Energy

Notes to Combined Financial Statements (Continued)

(WPZ), an entity under the common control of Williams, in exchange for $702 million in cash and 1.8 million WPZ limited partner units. As the Company and WPZ are under common control, no gain was recognized on this transaction in the Combined Statement of Operations. Accordingly, the $244 million difference between the cash consideration received and the historical net book value of the assets has been reflected in the Combined Statement of Equity for the year ended December 31, 2010. Since the WPZ units received in this transaction by the Company were intended to be (and now have been, as described below) distributed through a dividend to Williams, these units (as well as the tax effects associated with these units of $42 million) have been presented net within equity and are included in net transfers with Williams in 2010. Further, as a result of the limitations on the Company s ability to sell these units and the subsequent dividend to Williams, no gains on the value of the common units during the holding period have been recognized in the Combined Statement of Operations. In conjunction with the Piceance Sale, we entered into long-term contracts with WPZ for gathering and processing of our natural gas production in the area. Due to the continuation of significant direct cash flows related to these assets, historical operating results of these assets continue to be presented in the Combined Statement of Operations as continuing operations for all periods presented. In March, 2011, the 1.8 million WPZ units and related tax basis were distributed via dividend to Williams.

Discontinued operations

During the first quarter 2011, we initiated a formal process to pursue the divestiture of our holdings in the Arkoma Basin. As these assets are currently held for sale, will be eliminated from our ongoing operations, and we will not have any significant continuing involvement, we have reported the results of operations and financial position of the Arkoma operations as discontinued operations.

Additionally, the accompanying combined financial statements and notes include the results of operations of Williams former power business most of which was disposed in 2007 as discontinued operations. The discontinued operations have been included in these combined financial statements because contingent obligations related to this former business directly relate to Williams Gas Marketing Services, resulting in the potential of charges or benefits to the Company in periods subsequent to the exit from this business. See Note 11 for a discussion of contingencies related to this discontinued power business.

Unless indicated otherwise, the information in the Notes to Combined Financial Statements relates to continuing operations.

Summary of Significant Accounting Policies

Basis of combination

The combined financial statements include the accounts of the combined entities as set forth in Description of Business and Basis of Presentation above. Companies in which WPX Energy entities own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the company, are accounted for under the equity method. All material intercompany transactions have been eliminated.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the combined financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions which impact these financials include:

- Impairment assessments of long-lived assets and goodwill;
- Assessments of litigation-related contingencies;

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WPX Energy

Notes to Combined Financial Statements (Continued)

Valuations of derivatives;

Hedge accounting correlations and probability;

Estimation of oil and natural gas reserves.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Our cash and cash equivalents relate primarily to our international operations. We consider all investments with a maturity of three months or less when acquired to be cash equivalents.

Additionally, our domestic businesses currently participate in the Williams cash management program (see Note 4) rather than maintaining cash and cash equivalent balances.

Restricted cash

Restricted cash primarily consists of approximately $19 million in both 2010 and 2009 related to escrow accounts established as part of the settlement agreement with certain California utilities (see Note 11) and is included in noncurrent other assets.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. A portion of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Inventories

All inventories are stated at the lower of cost or market. Our inventories consist primarily of tubular goods and production equipment for future transfer to wells of $46 million in 2010 and $34 million in 2009. Additionally, we have natural gas in storage of $31 million in 2010 and $27 million in 2009 primarily related to our gas management activities. Inventory is recorded and relieved using the weighted average cost method except for production equipment which is on the specific identification method. We recorded lower of cost or market writedowns on natural gas in storage of $2 million in 2010, $7 million in 2009 and $35 million in 2008.

Properties and equipment

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to exploration expense. Other exploration costs, including geological and geophysical costs and lease rentals are charged to expense as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred whether productive or nonproductive.

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to

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WPX Energy

Notes to Combined Financial Statements (Continued)

be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of lease acquisition costs are included in exploration expense in the Combined Statement of Operations. A majority of the costs of acquired unproved reserves are associated with areas to which we or other producers have identified significant proved developed producing reserves. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of unproved reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. We refer to unproved lease acquisition costs and costs of acquired unproved reserves as unproved properties.

Other capitalized costs

Costs related to the construction or acquisition of field gathering, processing and certain other facilities are recorded at cost. Ordinary maintenance and repair costs are expensed as incurred.

Depreciation, depletion and amortization

Capitalized exploratory and developmental drilling costs, including lease and well equipment and intangible development costs are depreciated and amortized using the units-of-production method based on estimated proved developed oil and gas reserves on a field basis or concession for our international properties. International concession reserve estimates are limited to production quantities estimated through the life of the concession. Depletion of producing leasehold costs is based on the units-of-production method using estimated proved oil and gas reserves on a field basis. In arriving at rates under the units-of-production methodology, the quantities of proved oil and gas reserves are established based on estimates made by our geologists and engineers.

Costs related to gathering, processing and certain other facilities are depreciated on the straight-line method over the estimated useful lives.

Gains or losses from the ordinary sale or retirement of properties and equipment are recorded in other net included in operating income (loss).

Impairment of long-lived assets

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate, in our management s judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management s estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the book value of the assets, then a subsequent analysis is performed using discounted cash flows.

Costs of acquired unproved reserves are assessed for impairment using estimated fair value determined through the use of future discounted cash flows on a field basis and considering market participants future drilling plans.

WPX Energy

Notes to Combined Financial Statements (Continued)

Judgments and assumptions are inherent in our management s estimate of undiscounted future cash flows and an asset s fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs and appropriate discount rates.

Asset retirement obligations

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation (ARO). These estimates include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market risk premium. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense in lease and facility operating expense included in costs and expenses.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated at least annually (in the fourth quarter) for impairment by first comparing our management s estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit s goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess.

As a result of significant declines in forward natural gas prices during third quarter of 2010, we performed an interim impairment assessment of our goodwill related to our domestic production reporting unit. As a result of that assessment, we recorded an impairment of goodwill of approximately $1 billion (see Note 6).

Judgments and assumptions are inherent in our management s estimate of future cash flows used to determine the estimate of the reporting unit s fair value.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Combined Balance Sheet in derivative assets and derivative liabilities as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

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WPX Energy

Notes to Combined Financial Statements (Continued)

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We have also designated a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in revenues or costs and operating expenses dependent upon the underlying hedge transaction.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in accumulated other comprehensive income (loss) (AOCI) and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative s change in fair value is recognized currently in revenues. Gains or losses deferred in AOCI associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in AOCI until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in AOCI is recognized in revenues at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in revenues dependent upon the underlying of the hedged transaction.

Certain gains and losses on derivative instruments included in the Combined Statement of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially;
- Realized gains and losses on derivatives held for trading purposes; and
- Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

WPX Energy

Notes to Combined Financial Statements (Continued)

Business segment information

The Company has a single operating segment that consists of all continuing operations, including gas management and oil and gas production activities. An operating segment is a component of an entity that engages in activities from which it may earn revenues and incur expenses, and for which discrete financial information is available and regularly reviewed by the chief operating decision maker for the purposes of assessing performance and allocating resources. We are controlled by Williams and we have determined that our chief operating decision maker is Williams Chief Executive Officer (who also serves as the Chairman of our Board of Directors). Performance evaluation and resource allocation decisions are made by our chief operating decision maker based on financial information presented for WPX Energy as a single operating segment.

Oil and gas sales revenues

Revenues for sales of natural gas, oil and condensate and natural gas liquids are recognized when the product is sold and delivered. Revenues from the production of natural gas in properties for which we have an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Our cumulative net natural gas imbalance position based on market prices as of December 31, 2010 and 2009 was insignificant. Additionally, oil and gas sales revenues include hedge gains realized on production sold of $333 million in 2010, $615 million in 2009 and $34 million in 2008.

Gas management revenues and expenses

Revenues for sales related to gas management activities are recognized when the product is sold and physically delivered. Our gas management activities to date include purchases and subsequent sales to WPZ for fuel and shrink gas (see Note 4). Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges. The Company also sells natural gas purchased from working interest owners in operated wells and other area third party producers. The revenues and expenses related to these marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Charges for unutilized transportation capacity included in gas management expenses were $48 million in 2010, $21 million in 2009 and $8 million in 2008.

Capitalization of interest

We capitalize interest during construction on projects with construction periods of at least three months or a total estimated project cost in excess of $1 million. The interest rate used is the rate charged to us by Williams, based on Williams average quarterly interest rate on its debt.

Income taxes

The Company s domestic operations are included in the consolidated federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision for the Company has been calculated on a separate return basis, except for certain state and federal tax attributes (primarily minimum tax credit carry-forwards) for which the actual allocation (if any) cannot be determined until the consolidated tax returns are complete for the year in which an income tax deconsolidation event occurs. This allocation methodology results in the recognition of deferred assets and liabilities for the differences between the financial statement carrying amounts and their respective tax basis, except to the extent of deferred taxes on income considered to be permanently reinvested in foreign jurisdictions. Deferred tax assets and liabilities are measured using enacted tax rates for the years in which those temporary differences are expected to be

WPX Energy

Notes to Combined Financial Statements (Continued)

recovered or settled. In addition, Williams manages its tax position based upon its entire portfolio which may not be indicative of tax planning strategies available to us if we were operating as an independent company.

Employee stock-based compensation

Certain employees providing direct service to the Company participate in Williams common-stock-based awards plans. The plans provide for Williams common-stock-based awards to both employees and Williams non-management directors. The plans permit the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets.

Williams charges us for compensation expense related to stock-based compensation awards granted to our direct employees. Stock based compensation is also a component of allocated amounts charged to us by Williams for general and administrative personnel providing services on our behalf.

Foreign exchange

Translation gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the United States dollar are included in the results of operations as incurred.

Earnings (loss) per share

Historical earnings per share are not presented since the Company s common stock was not part of the capital structure of Williams for the periods presented.

Unaudited Supplemental Pro forma combined loss per share

Basic and diluted pro forma combined loss per share for the year ended December 31, 2010 were calculated by assuming common shares outstanding, reflecting common shares owned by Williams after the stock split and common shares held by the purchasers in the Offering. Additionally, for purposes of calculating basic and diluted pro forma combined loss per share, our historical net loss was further increased by $88 million to reflect incremental interest expense (net of tax) related to the portion of the $1,697 million distribution that exceeds the proceeds from the Offering and our earnings for the previous twelve months.

2. Restatement of Prior Periods

In the first quarter of 2011, we determined that for the years ended December 31, 2010, 2009 and 2008, we had failed to properly accrue estimates of the minimum annual volumetric throughput requirements associated with certain of our compression services agreements. As a result of this error, our costs and expenses were understated by $3 million, $5 million and $6 million for the years ended December 31, 2010, 2009 and 2008, respectively. Based on guidance set forth in Staff Accounting Bulletin No. 99, *Materiality* and in Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* (SAB 108), we have determined that these amounts are immaterial to each of the periods affected and, therefore, we are not required to amend our previously filed reports. However, if these adjustments were recorded in 2011, we believe the impact could be material to this reporting period. As a result, we have adjusted, in the tables below, our previously reported results for the years ended December 31, 2010, 2009 and 2008 for these amounts as required by SAB 108. In addition to recording the obligations associated with the minimum annual volumetric throughput requirements previously discussed, we have made five other immaterial adjustments to prior year amounts as follows: (1) oil and gas sales revenue decrease of $3 million and $2 million for additional royalties expected to be paid for the years ended December 31, 2010 and 2009, respectively; (2) gas management revenue decrease of

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WPX Energy

Notes to Combined Financial Statements (Continued)

$3 million for natural gas measurement adjustments related to the year ended December 31, 2008; (3) gas management expense decrease of $3 million and $1 million for adjustments made under gas purchase agreements for the years ended December 31, 2010 and 2009, respectively; (4) depreciation, depletion and amortization expense increase of $1 million related to the year ended December 31, 2010; and (5) bad debt expense increase of $1 million related the year ended December 31, 2010.

	Year Ended December 31, 2010			Year Ended December 31, 2009			Year Ended December 31, 2008		
	Previously Reported(1)	Adjustments	As Adjusted	Previously Reported(1)	Adjustments	As Adjusted	Previously Reported(1)	Adjustments	As Adjusted
Revenues:									
Oil and gas sales, including affiliate	$ 2,228	$ (3)	$ 2,225	$ 2,170	$ (2)	$ 2,168	$ 2,882	$	$ 2,882
Gas management, including affiliate	1,742		1,742	1,456		1,456	3,244	(3)	3,241
Hedge ineffectiveness and mark to market gains and losses	27		27	18		18	29		29
Other	40		40	39		39	32		32
Total revenues	4,037	(3)	4,034	3,683	(2)	3,681	6,187	(3)	6,184
Costs and expenses:									
Lease and facility operating, including affiliate	286		286	263		263	272		272
Gathering, processing and transportation, including affiliate	323	3	326	268	5	273	223	6	229
Taxes other than income	125		125	93		93	254		254
Gas management (including charges for unutilized pipeline capacity)	1,774	(3)	1,771	1,496	(1)	1,495	3,248		3,248
Exploration	73		73	54		54	37		37
Depreciation, depletion and amortization	874	1	875	887		887	738		738
Impairment of producing properties and costs of acquired unproved reserves	678		678	15		15			

Goodwill impairment	1,003		1,003						
General and administrative, including affiliate	252	1	253	251		251	247		247
Gain on sale of contractual right to international production payment							(148)		(148)
Other net	(19)		(19)	33		33	6		6
Total costs and expenses	5,369	2	5,371	3,360	4	3,364	4,877	6	4,883
Operating income (loss)	(1,332)	(5)	(1,337)	323	(6)	317	1,310	(9)	1,301
Interest expense, including affiliate	(124)		(124)	(100)		(100)	(74)		(74)
Interest capitalized	16		16	18		18	20		20
Investment income and other	21		21	8		8	22		22
Income (loss) before income taxes	(1,419)	(5)	(1,424)	249	(6)	243	1,278	(9)	1,269
Provision (benefit) for income taxes	(148)	(2)	(150)	96	(2)	94	455	(3)	452
Income (loss) from continuing operations	(1,271)	(3)	(1,274)	153	(4)	149	823	(6)	817
Loss from discontinued operations	(8)		(8)	(7)		(7)	(87)		(87)
Net income (loss)	(1,279)	(3)	(1,282)	146	(4)	142	736	(6)	730
Less: Net income attributable to noncontrolling interests	8		8	6		6	8		8
Net income (loss) attributable to WPX Energy	$ (1,287)	$ (3)	$ (1,290)	$ 140	$ (4)	$ 136	$ 728	$ (6)	$ 722

(1) Includes reclassifications made to report the results of operations of our Arkoma properties as discontinued operations (See Note 1).

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Notes to Combined Financial Statements (Continued)

	December 31, 2010			December 31, 2009		
	Previously Reported(1)	Adjustments	As Adjusted	Previously Reported(1)	Adjustments	As Adjusted
Assets						
Current assets:						
Cash and cash equivalents	$ 37	$	$ 37	$ 34	$	$ 34
Accounts receivable:						
Trade, net of allowance for doubtful accounts of $15 and $19 as of December 31, 2010 and 2009, respectively	362		362	361	(2)	359
Affiliate	60		60	54		54
Derivative assets	400		400	650		650
Inventories	77		77	61		61
Other	22		22	41		41
Total current assets	958		958	1,201	(2)	1,199
Investments	105		105	95		95
Properties and equipment, net (successful efforts method of accounting)	8,450	(1)	8,449	7,662		7,662
Derivative assets	173		173	444		444
Goodwill, net				1,003		1,003
Other noncurrent assets	161		161	150		150
Total assets	$ 9,847	$ (1)	$ 9,846	$ 10,555	$ (2)	$ 10,553
Liabilities and Equity						
Current liabilities:						
Accounts payable:						
Trade	$ 446	$ 5	$ 451	$ 460	$ 2	$ 462
Affiliate	64		64	37		37
Accrued and other current liabilities	144	14	158	220	11	231
Deferred income taxes	87		87	28		28
Notes payable to Williams	2,261		2,261	1,216		1,216
Derivative liabilities	146		146	578		578
Total current liabilities	3,148	19	3,167	2,539	13	2,552
Deferred income taxes	1,629		1,629	1,841		1,841
Derivative liabilities	143		143	428		428
Asset retirement obligations	282		282	235		235
Other noncurrent liabilities	125		125	92		92

Contingent liabilities and commitments *(Note 11)*						
Equity:						
Owner s net equity:						
Owner s net investment	4,280	(20)	4,260	5,284	(15)	5,269
Accumulated other comprehensive income	168		168	72		72
Total owner s net equity	4,448	(20)	4,428	5,356	(15)	5,341
Noncontrolling interests in combined subsidiaries	72		72	64		64
Total equity	4,520	(20)	4,500	5,420	(15)	5,405
Total liabilities and equity	$ 9,847	$ (1)	$ 9,846	10,555	$ (2)	10,553

(1) Includes reclassifications made to report the financial position of our Arkoma properties as held for sale (See Note 1).

WPX Energy

Notes to Combined Financial Statements (Continued)

3. Discontinued Operations

Summarized Results of Discontinued Operations

	2010	2009	2008
Revenues	$ 16	$ 17	$ 43
Income (loss) from discontinued operations before impairments, gain on sale and income taxes	$ (13)	$ (11)	$ 4
(Impairments) and gain on sale			(140)
Benefit for income taxes	5	4	49
Loss from discontinued operations	$ (8)	$ (7)	$ (87)

(Impairments) and gain on sale for 2008 includes $148 million of impairments related to properties in the Arkoma Basin and the final proceeds from the 2007 sale of Williams former power business.

The assets of our holdings in the Arkoma Basin comprise significantly less than 1% of our total assets as of December 31, 2010 and 2009 and are reported in other assets and other noncurrent assets on our Combined Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

4. Related Party Transactions

Transactions with Williams and Other Affiliated Entities

Our employees are also employees of Williams. Williams charges us for the payroll and benefit costs associated with operations employees (referred to as direct employees) and carries the obligations for many employee-related benefits in its financial statements, including the liabilities related to employee retirement and medical plans. Our share of those costs is charged to us through affiliate billings and reflected in lease and facility operating and general and administrative within costs and expenses in the accompanying Combined Statement of Operations.

In addition, Williams charges us for certain employees of Williams who provide general and administrative services on our behalf (referred to as indirect employees). These charges are either directly identifiable or allocated to our operations. Direct charges include goods and services provided by Williams at our request. Allocated general corporate costs are based on our relative usage of the service or on a three-factor formula, which considers revenues; properties and equipment; and payroll. Our share of direct general and administrative expenses and our share of allocated general corporate expenses is reflected in general and administrative expense in the accompanying Combined Statement of Operations. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of our costs of doing business incurred by Williams. We also have operating activities with WPZ and another Williams subsidiary. Our revenues include revenues from the following types of transactions:

Sales of natural gas liquids (NGLs) related to our production to WPZ at market prices at the time of sale and included within our oil and gas sales revenues; and

Sale to WPZ and another Williams subsidiary of natural gas procured by Williams Gas Marketing Services for those companies fuel and shrink replacement at market prices at the time of sale and included in our gas management revenues.

Our costs and operating expenses include the following services provided by WPZ:

Gathering, treating and processing services under several contracts for our production primarily in the San Juan and Piceance Basins; and

WPX Energy

Notes to Combined Financial Statements (Continued)

Pipeline transportation for both our oil and gas sales and gas management activities which includes commitments totaling $442 million (see Note 11 for capacity commitments with affiliates).

In addition, through an agency agreement, we manage the jurisdictional merchant gas sales for Transcontinental Gas Pipe Line Company LLC (Transco), an indirect, wholly owned subsidiary of WPZ. We are authorized to make gas sales on Transco s behalf in order to manage its gas purchase obligations. Although there is no exchange of payments between us and Transco for these transactions, we receive all margins associated with jurisdictional merchant gas sales business and, as Transco s agent, assume all market and credit risk associated with such sales. Gas sales and purchases related to our management of these jurisdictional merchant gas sales are included in gas management revenues and expenses, respectively in the Combined Statement of Operations and the margins we realized related to these activities totaled less than $1 million in each of the years ended December 31, 2010, 2009 and 2008.

We manage a transportation capacity contract for WPZ. To the extent the transportation is not fully utilized or does not recover full-rate demand expense, WPZ reimburses us for these transportation costs. These reimbursements to us totaled approximately $10 million, $9 million and $11 million for the years ended December 31, 2010, 2009 and 2008, respectively, and are included in gas management revenues.

WPZ periodically enters into derivative contracts with us to hedge their forecasted NGL sales and natural gas purchases. We enter into offsetting derivative contracts with third parties at equivalent pricing and volumes. These contracts are included in derivative assets and liabilities on the Combined Balance Sheet (see Note 15).

Williams utilizes a centralized approach to cash management and the financing of its businesses. Cash receipts from the Company s domestic operations are transferred to Williams on a regular basis and cleared through unsecured promissory note agreements with Williams. Cash expenditures for property operating and development costs and expenses are also cleared through these unsecured promissory note agreements with Williams. The amounts receivable or due under the note agreements are due on demand, however, Williams has agreed to not make demand on these notes payable prior to the completion of the Offering. Williams has also agreed to forgive or contribute any amounts outstanding on these note agreements prior to or concurrent with the Contribution. The notes bear interest based on Williams weighted average cost of debt and such interest is added monthly to the note principal. The interest rate for the notes payable to Williams was 8.08% and 8.01% at December 31, 2010 and 2009, respectively. As of December 31, 2010 and 2009, our net amounts due to Williams are reflected as notes payable to Williams. None of Williams cash or debt at the Williams corporate level has been allocated to the Company in the financial statements. Changes in the notes represent any funding required from Williams for working capital, acquisitions or capital expenditures and after giving effect to the Company s transfers to Williams from its cash flows from operations or proceeds from sales of assets. Concurrently with or shortly following the consummation of the Offering, we expect to issue up to $1.5 billion aggregate principal amount of senior unsecured notes. Furthermore, we expect to distribute the net proceeds from the Offering and the issuance of the notes in excess of approximately $500 million to Williams.

Under Williams cash-management system, certain cash accounts reflect negative balances to the extent checks written have not been presented for payment. These negative amounts represent obligations and have been reclassified to accounts payable-affiliate. Accounts payable-affiliate includes approximately $38 million and $26 million of these negative balances at December 31, 2010 and 2009, respectively.

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Notes to Combined Financial Statements (Continued)

Below is a summary of the related party transactions discussed above:

	2010	2009	2008
		(Millions)	
Oil and gas sales revenues sales of NGLs to WPZ	$ 277	$ 116	$ 36
Gas management revenues sales of natural gas for fuel and shrink to WPZ and another Williams subsidiary	509	431	1,042
Lease and facility operating expenses from Williams-direct employee salary and benefit costs	23	23	19
Gathering, processing and transportation expense from WPZ:			
Gathering and processing	163	72	44
Transportation	25	28	34
General and administrative from Williams:			
Direct employee salary and benefit costs	102	100	92
Charges for general and administrative services	58	60	60
Allocated general corporate costs	64	63	56
Other	12	13	12
Interest expense on notes payable to Williams	119	92	64

In addition, the current amount due to or from affiliates consists of normal course receivables and payables resulting from the sale of products to and cost of gathering services provided by WPZ. Below is a summary of these payables and receivables which are settled monthly:

	December 31, 2010	December 31, 2009
	(Millions)	
Current:		
Accounts receivable:		
Due from WPZ and another Williams subsidiary	$ 60	$ 54
Accounts payable:		
Due to WPZ	$ 12	$ 2
Due to Williams for cash overdraft.	38	26
Due to Williams for accrued payroll and benefits	14	9
	$ 64	$ 37

As discussed in Note 1, the Company sold certain gathering and processing assets in Colorado s Piceance Basin to WPZ. Under an Omnibus Agreement entered into in connection with this transaction, we are obligated to reimburse

WPZ for (i) amounts incurred by WPZ or its subsidiaries for any costs required to complete the pipeline and compression projects known collectively as the Ryan Gulch Expansion Project, (ii) amounts incurred by WPZ or its subsidiaries prior to January 31, 2011, related to the development of a cryogenic processing arrangement with a subsidiary of Williams, up to $20 million, and (iii) amounts incurred by WPZ or its subsidiaries for notice of violation or enforcement actions related to compression station land use permits or other losses, costs and expenses related to certain surface lease use agreements. In addition, WPZ is obligated to reimburse us for any costs related to the pipeline and compression projects known collectively as the Kokopelli Expansion irrespective of whether those costs were incurred prior to the effective date of the transaction. Estimated amounts for these obligations were recorded at the time of the sale and were less than $5 million. Differences in the estimated amounts and actual payments will be reflected within

WPX Energy

Notes to Combined Financial Statements (Continued)

Owner s Net Investment consistent with the treatment of the difference in the net book value and proceeds from sale.

5. Investment Income and Other

Investment income and other for the years ended December 31, 2010, 2009 and 2008, is as follows:

	Years Ended December 31,		
	2010	2009	2008
		(Millions)	
Equity earnings	$ 20	$ 18	$ 20
Impairment of cost-based investment		(11)	
Other	1	1	2
Total investment income and other	$ 21	$ 8	$ 22

Impairment of cost-based investment in 2009 reflects an $11 million full impairment of our 4 percent interest in a Venezuelan corporation that owns and operates oil and gas activities in Venezuela.

Investments

Investment balance as of December 31, 2010 and 2009 is as follows:

	December 31,	
	2010	2009
	(Millions)	
Petrolera Entre Lomas S.A. 40.8%	$ 82	$ 81
Other	23	14
	$ 105	$ 95

Dividends and distributions received from companies accounted for by the equity method were $19 million in 2010, $9 million in 2009 and $11 million in 2008.

6. Asset Sales, Impairments, Exploration Expenses and Other Accruals

The following table presents a summary of significant gains or losses reflected in impairment of producing properties and costs of acquired unproved reserves, goodwill impairment and other net within costs and expenses:

	Years Ended December 31, 2010	2009	2008
		(Millions)	
Goodwill impairment	$ 1,003	$	$
Impairment of producing properties and costs of acquired unproved reserves*	678	15	
Penalties from early release of drilling rigs included in other (income) expense net		32	
Gain on sale of contractual right to an international production payment			(148)
(Gain) loss on sales of other assets	(22)	1	1

* Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.

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Notes to Combined Financial Statements (Continued)

As a result of significant declines in forward natural gas prices during 2010, we performed an interim impairment assessment of our capitalized costs related to goodwill and domestic producing properties. As a result of these assessments, we recorded an impairment of goodwill, as noted above, and impairments of our capitalized costs of certain natural gas producing properties in the Barnett Shale of $503 million and capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million (see Note 14).

Based on a comparison of the estimated fair value to the carrying value, we recorded a $15 million impairment in 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth Basin (see Note 14).

Our impairment analyses included an assessment of undiscounted (except for the costs of acquired unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities, and natural gas reserve quantities.

In July 2010, we sold a portion of our gathering and processing facilities in the Piceance Basin to a third party for cash proceeds of $30 million resulting in a gain of $12 million. The remaining portion of the facilities was part of the Piceance Sale (see Note 1). Also in 2010, we exchanged undeveloped leasehold acreage in different areas with a third party resulting in a $7 million gain.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. We obtained this interest (for which we allocated no value) through the acquisition of Barrett Resources Corporation in 2001 and there were no operations associated with this interest. As a result of the contract termination, we have no further interests associated with the crude oil concession which is located in Peru.

The following presents a summary of exploration expenses:

	Years Ended December 31		
	2010	2009	2008
	(Millions)		
Geologic and geophysical costs	$ 22	$ 33	$ 13
Dry hole costs	17	11	16
Unproved leasehold property impairment, amortization and expiration	34	10	8
Total exploration expense	$ 73	$ 54	$ 37

Additional Items

Production and ad valorem taxes in 2008 include a $34 million accrual (which was reduced by $5 million in 2009) for additional Wyoming severance and ad valorem taxes associated with our initial estimate for settlement of an assessment initially for production years 2000 through 2002, but expanded through 2008 by the Wyoming Department of Audit (DOA), of additional severance tax and interest and notification of an increase in the taxable value of our interests for ad valorem tax purposes. Associated with this charge is an interest expense accrual of $4 million. All matters related to this issue have been settled with the State and respective counties for the amounts accrued.

WPX Energy

Notes to Combined Financial Statements (Continued)

7. Properties and Equipment

Properties and equipment is carried at cost and consists of the following:

	Estimated Useful Life(a) (Years)	December 31, 2010	December 31, 2009
		(Millions)	
Proved properties	(b)	$ 9,822	$ 8,784
Unproved properties	(c)	1,893	922
Gathering, processing and other facilities	15-25	119	787
Construction in progress	(c)	603	573
Other	3-25	127	123
Total properties and equipment, at cost		12,564	11,189
Accumulated depreciation, depletion and amortization		(4,115)	(3,527)
Properties and equipment net		$ 8,449	$ 7,662

(a) Estimated useful lives are presented as of December 31, 2010.

(b) Proved properties are depreciated, depleted and amortized using the units-of-production method (see Note 1).

(c) Unproved properties and construction in progress are not yet subject to depreciation and depletion.

Unproved properties consist primarily of non-producing leasehold in the Williston Basin (Bakken Shale) and the Appalachian Basin (Marcellus Shale) and acquired unproved reserves in the Powder River and Piceance Basins.

On December 21, 2010, we closed the acquisition of 100 percent of the equity of Dakota-3 E&P Company LLC for $949 million, including closing adjustments. This company holds approximately 85,800 net acres on the Fort Berthold Indian Reservation in the Williston Basin of North Dakota. Approximately 85% of the acreage is undeveloped. Approximately $400 million of the purchase price was recorded as proved properties, $542 million as unproved properties within properties and equipment and $5 million of prepaid drilling costs (no significant working capital was acquired). Revenues and earnings for the acquired company were nominal and thus insignificant to us for the three years ended December 31, 2010, 2009 and 2008; accordingly, pro forma operating results would be substantially similar to those reflected on our historical Combined Statement of Operations.

As discussed in Notes 1 and 4, the Company sold certain gathering and processing assets in Colorado s Piceance Basin with a net book value of $458 million to WPZ.

In May 2010, we entered into a purchase agreement consisting primarily of non-producing leasehold acreage in the Appalachian Basin and a 5 percent overriding royalty interest associated with the acreage position for $599 million. We also acquired additional non-producing leasehold acreage in the Appalachian Basin for $164 million during the year.

Construction in progress includes $142 million in 2010 and $136 million in 2009 related to wells located in Powder River. In order to produce gas from the coal seams, an extended period of dewatering is required prior to natural gas production.

In 2009, we adopted Accounting Standards Update No. 2010-03, which aligned oil and gas reserve estimation and disclosure requirements to those in the Securities and Exchange Commission s final rule related thereto. Accordingly, our fourth quarter 2009 depreciation, depletion and amortization expense was approximately $17 million more than had it been computed under the prior requirements.

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Notes to Combined Financial Statements (Continued)

Asset Retirement Obligations

Our asset retirement obligations relate to producing wells, gas gathering well connections and related facilities. At the end of the useful life of each respective asset, we are legally obligated to plug producing wells and remove any related surface equipment and to cap gathering well connections at the wellhead and remove any related facility surface equipment.

A rollforward of our asset retirement obligation for the years ended 2010 and 2009 is presented below.

	2010	2009
	(Millions)	
Balance, January 1	$ 242	$ 194
Liabilities incurred during the period	43	18
Liabilities settled during the period	(2)	(1)
Liabilities associated with assets sold	(22)	
Estimate revisions	3	15
Accretion expense*	21	16
Balance, December 31	$ 285	$ 242
Amount reflected as current	$ 3	$ 7

* Accretion expense is included in lease and facility operating expense on the Combined Statement of Operations.

8. Accrued and other current liabilities

Accrued and other current liabilities as of December 31, 2010 and 2009 is as follows:

	December 31,	
	2010	2009
	(Millions)	
Taxes other than income taxes	$ 76	$ 126
Customer margin deposit payable	25	31
Other	57	74
	$ 158	$ 231

9. Unsecured Credit Agreement

We have an unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. In July 2010, the term of this facility was extended from December 2013 to December 2015. Under the credit agreement, we are not required to post collateral as long as the value of our domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of our obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. We are subject to additional covenants under the credit agreement including restrictions on hedge limits (70% of annual forecasted production as defined in the agreement), the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments during an event of default, such as dividends. In December 2010, a waiver with the same terms and restrictions as the original agreement, was executed that will allow us to also hedge up to 70% of annual forecasted oil production, as defined in the agreement.

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Notes to Combined Financial Statements (Continued)

10. Income Taxes

The Company s domestic operations are included in the consolidated federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision for the Company has been calculated on a separate return basis, except for certain state and federal tax attributes (primarily minimum tax credit carry-forwards) for which the actual allocation (if any) cannot be determined until the consolidated tax returns are complete for the year in which an income tax deconsolidation event occurs. If the income tax deconsolidation event had occurred December 31, 2010, the Company s allocated share of minimum tax credit carry-forwards are estimated to be in the range of $35 to $45 million. This estimate of potential tax attributes has not been included in these financial statements. The valuation allowance at December 31, 2010 and 2009 serves to reduce the recognized tax assets of $22 million associated with state losses, net of federal benefit, to an amount that will more likely than not be realized by the Company. There have been no significant effects on the income tax provision associated with changes in the valuation allowance for the years ended December 31, 2010, 2009 and 2008. Williams manages its tax position based upon its entire portfolio which may not be indicative of tax planning strategies available to us if we were operating as an independent company.

The provision (benefit) for income taxes from continuing operations includes:

	Years Ended December 31, 2010	2009	2008
	(Millions)		
Provision (benefit):			
Current:			
Federal	$ 7	$ (17)	$ (52)
State	1	(1)	(3)
Foreign	11	9	8
	19	(9)	(47)
Deferred:			
Federal	(159)	97	470
State	(10)	6	30
Foreign			(1)
	(169)	103	499
Total provision (benefit)	$ (150)	$ 94	$ 452

Reconciliations from the provision (benefit) for income taxes from continuing operations at the federal statutory rate to the realized provision (benefit) for income taxes are as follows:

	Years Ended December 31, 2010	2009	2008
		(Millions)	
Provision (benefit) at statutory rate	$ (498)	$ 85	$ 444
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(6)	3	18
Foreign operations net	3	5	(2)
Goodwill impairment	351		
Other net		1	(8)
Provision (benefit) for income taxes	$ (150)	$ 94	$ 452

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Notes to Combined Financial Statements (Continued)

Income (loss) from continuing operations before income taxes includes $36 million, $21 million, and $30 million of foreign income in 2010, 2009, and 2008, respectively.

Significant components of deferred tax liabilities and deferred tax assets are as follows:

	December 31, 2010	December 31, 2009
	(Millions)	
Deferred tax liabilities:		
Properties and equipment	$ 1,723	$ 1,939
Derivatives, net	110	61
Total deferred tax liabilities	1,833	2,000
Deferred tax assets:		
Accrued liabilities and other	117	131
State loss carryovers	22	22
Total deferred tax assets	139	153
Less: valuation allowance	22	22
Total net deferred tax assets	117	131
Net deferred tax liabilities	$ 1,716	$ 1,869

Undistributed earnings of certain combined foreign subsidiaries at December 31, 2010, totaled approximately $109 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in foreign operations.

The payments and receipts for domestic income taxes were made to or received from Williams via the notes payable to parent (see Note 4) in accordance with our historical tax allocation procedure. The cash payments for domestic income taxes (net of refunds) were $5 million in 2010. Cash receipts for domestic income taxes (net of payments) were $13 million and $44 million in 2009 and 2008, respectively. Additionally, payments made directly to international taxing authorities were $8 million, $4 million, and $8 million in 2010, 2009, and 2008, respectively.

We recognize related interest and penalties as a component of income tax expense. The amounts accrued for interest and penalties are insignificant.

As of December 31, 2010, the amount of unrecognized tax benefits is insignificant.

During the first quarter of 2011, Williams finalized settlements with the IRS for 1997 through 2008. These settlements will not have a material impact on our unrecognized tax benefits. The statute of limitations for most states expires one year after expiration of the IRS statute. Income tax returns for our Colombian (2008 through 2010), Venezuelan (2006 through 2010) and Argentine (2003 through 2010) entities are also open to audit.

During the next 12 months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter will result in a significant increase or decrease of our unrecognized tax benefit.

11. Contingent Liabilities and Commitments

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify as a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class members for class certification, reserved two claims for court resolution, resolved all other class

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Notes to Combined Financial Statements (Continued)

claims relating to past calculation of royalty and overriding royalty payments, and established certain rules to govern future royalty and overriding royalty payments. This settlement resolved all claims relating to past withholding for ad valorem tax payments and established a procedure for refunds of any such excess withholding in the future. The first reserved claim is whether we are entitled to deduct in our calculation of royalty payments a portion of the costs we incur beyond the tailgates of the treating or processing plants for mainline pipeline transportation. We received a favorable ruling on our motion for summary judgment on the first reserved claim. Plaintiffs appealed that ruling and the Colorado Court of Appeals found in our favor in April 2011. The second reserved claim relates to whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are thus entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate trial on the second reserved claim following resolution of the first reserved claim. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims. However, it is reasonably possible that the ultimate resolution of this item could result in a future charge that may be material to our results of operations.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5, 2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states, but such guidelines are expected in the future. However, the timing of receipt of the necessary guidelines is uncertain. In addition, these interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and will vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. From January 2004 through December 2010, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $55 million. Based on correspondence in 2009 with the ONRR s predecessor, we believe our assumptions in the calculations have been consistent with the requirements. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments and the effect could be material to our results of operations.

Environmental matters

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, and one hour nitrogen dioxide emission limits. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matters related to Williams former power business

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western

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Notes to Combined Financial Statements (Continued)

states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of natural gas-related information to trade publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. On January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. We expect that the Colorado plaintiffs will appeal, but the appeal cannot occur until the case against the remaining defendant is concluded.

In the other cases, our joint motions for summary judgment to preclude the plaintiffs state law claims based upon federal preemption have been pending since late 2009. If the motions are granted, we expect a final judgment in our favor which the plaintiffs could appeal. If the motions are denied, the current stay of activity would be lifted, class certification would be addressed, and discovery would be completed as the cases proceed towards trial. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At December 31, 2010, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

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Notes to Combined Financial Statements (Continued)

Summary

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. As of December 31, 2010 and 2009, the Company had accrued approximately $21 million and $30 million, respectively, for loss contingencies associated with royalty litigation, reporting of natural gas information to trade publications and other contingencies. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

Commitments

As part of managing our commodity price risk, we utilize contracted pipeline capacity (including capacity on affiliates systems, resulting in a total of $442 million for all years) primarily to move our natural gas production to other locations in an attempt to obtain more favorable pricing differentials. Our commitments under these contracts are as follows:

	(Millions)
2011	$ 204
2012	208
2013	200
2014	174
2015	166
Thereafter	635
Total	$ 1,587

We have certain commitments to an equity investee and others for natural gas gathering and treating services, which total $447 million over approximately eleven years.

We have a long-term obligation to deliver on a firm basis 200,000 MMBtu per day of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. This obligation expires in 2014.

In connection with a gathering agreement entered into by WPZ with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu per day of natural gas at Transco Station 515 (Marcellus Basin) at market prices from the same third party. Purchases under the 12-year contract are expected to begin in the third quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

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Notes to Combined Financial Statements (Continued)

Future minimum annual rentals under noncancelable operating leases as of December 31, 2010, are payable as follows:

	(Millions)
2011	$ 14
2012	10
2013	9
2014	4
2015	3
Thereafter	15
Total	$ 55

Total rent expense, excluding month-to-month rentals, was $13 million, $22 million and $21 million in 2010, 2009 and 2008, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting.

12. Employee Benefit Plans

Certain benefit costs associated with direct employees who support our operations are determined based on a specific employee basis and are charged to us by Williams as described below. These pension and post retirement benefit costs include amounts associated with vested participants who are no longer employees. As described in Note 4, Williams also charges us for the allocated cost of certain indirect employees of Williams who provide general and administrative services on our behalf. Williams includes an allocation of the benefit costs associated with these Williams employees based upon a Williams determined benefit rate, not necessarily specific to the employees providing general and administrative services on our behalf. As a result, the information described below is limited to amounts associated with the direct employees supporting our operations.

For the periods presented, we were not the plan sponsor for these plans. Accordingly, our Combined Balance Sheet does not reflect any assets or liabilities related to these plans.

Pension plans

Williams is the sponsor of noncontributory defined benefit pension plans that provide pension benefits for its eligible employees. Pension expense charged to us by Williams for 2010, 2009 and 2008 totaled $7 million, $7 million and $3 million, respectively.

Other postretirement benefits

Williams is the sponsor of subsidized retiree medical and life insurance benefit plans (other postretirement benefits) that provides benefits to certain eligible participants, generally including employees hired on or before December 31, 1991, and other miscellaneous defined participant groups. The allocation of cost for the plan anticipates future cost-sharing changes to the plan that are consistent with Williams expressed intent to increase the retiree contribution level, generally in line with health care cost increases. Other postretirement benefit expense charged to us by Williams for 2010, 2009, and 2008 totaled less than $1 million for each period.

Defined contribution plan

Williams also is the sponsor of a defined contribution plan that provides benefits to certain eligible participants and thus has charged us compensation expense of $5 million, $5 million and $4 million in 2010,

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Notes to Combined Financial Statements (Continued)

2009 and 2008, respectively, for Williams matching contributions to this plan. Additionally, Apco maintains a defined contribution plan for its employees. Total annual compensation expense related to Apco s plan was approximately $0.1 million for each period.

13. Stock-Based Compensation

Certain of our direct employees participate in The Williams Companies, Inc. 2007 Incentive Plan, which provides for Williams common-stock-based awards to both employees and Williams nonmanagement directors. The plan permits the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets. Additionally, certain of our direct employees participate in Williams Employee Stock Purchase Plan (ESPP). The ESPP enables eligible participants to purchase through payroll deductions a limited amount of Williams common stock at a discounted price.

We are charged by Williams for stock-based compensation expense related to our direct employees. Williams also charges us for the allocated costs of certain indirect employees of Williams (including stock-based compensation) who provide general and administrative services on our behalf and may become our employees in the future. However, information included in this note is limited to stock-based compensation associated with the direct employees (see Note 4 for total costs charged to us by Williams).

Total stock-based compensation expense included in general and administrative expense for the years ended December 31, 2010, 2009 and 2008 was $14 million, $13 million, and $11 million, respectively.

Employee stock-based awards

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant.

Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

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Notes to Combined Financial Statements (Continued)

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2010.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2009	1.6	$ 17.47	
Granted	0.2	$ 21.22	
Exercised	(0.1)	$ 7.65	$ 2
Expired	(0.1)	$ 42.29	
Forfeited		$	
Outstanding at December 31, 2010	1.6	$ 18.23	$ 13
Exercisable at December 31, 2010	1.2	$ 18.20	$ 10

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $2 million, $0.2 million, and $7 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2010.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$2.58 to $11.84	0.6	$ 8.79	4.9	0.5	$ 7.88	3.4
$11.85 to 21.67	0.6	$ 20.32	6.1	0.4	$ 19.79	4.3
$21.68 to $33.65	0.2	$ 27.84	6.0	0.2	$ 27.84	6.0
$33.66 to $36.50	0.2	$ 36.21	5.9	0.1	$ 36.09	5.5
Total	1.6	$ 18.23	5.6	1.2	$ 18.20	4.4

The estimated fair value at date of grant of options for Williams common stock granted in each respective year, using the Black-Scholes option pricing model, is as follows:

	2010	2009	2008
Weighted-average grant date fair value of options granted	$ 7.02	$ 5.60	$ 12.83
Weighted-average assumptions:			
Dividend yield	2.6%	1.6%	1.2%
Volatility	39.0%	60.8%	33.4%
Risk-free interest rate	3.0%	2.3%	3.5%
Expected life (years)	6.5	6.5	6.5

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of Williams stock and the implied volatility of Williams stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

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Notes to Combined Financial Statements (Continued)

Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2010.

Restricted Stock Units	**Shares (Millions)**	**Weighted-Average Fair Value***
Nonvested at December 31, 2009	1.7	$ 18.24
Granted	0.6	$ 21.19
Forfeited	(0.1)	$ 19.36
Cancelled	(0.1)	$ 0.00
Vested	(0.3)	$ 28.35
Nonvested at December 31, 2010	1.8	$ 17.96

* Performance-based shares are primarily valued using the end-of-period market price until certification that the performance objectives have been completed, a value of zero once it has been determined that it is unlikely that performance objectives will be met, or a valuation pricing model. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2010	**2009**	**2008**
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$ 21.19	$ 10.53	$ 32.34
Total fair value of restricted stock units vested during the year ($ s in millions)	$ 9	$ 8	$ 6

14. Fair Value Measurements

Fair value is the amount received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange traded;

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or

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Notes to Combined Financial Statements (Continued)

indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 primarily consists of over-the-counter (OTC) instruments such as forwards, swaps, and options. These options, which hedge future sales of production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Prior to 2009, these options were included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. However, due to the increased transparency, we now consider this input to be observable and have included these options in Level 2; and

Level 3 Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements Using:

	December 31, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$ 97	$ 474	$ 2	$ 573	$ 178	$ 912	$ 4	$ 1,094
Energy derivative liabilities	$ 78	$ 210	$ 1	$ 289	$ 177	$ 826	$ 3	$ 1,006

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include

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Notes to Combined Financial Statements (Continued)

commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the value of our derivatives portfolio expiring in the next 24 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2010, consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers in or out of Level 1 and Level 2 occurred during the year ended December 31, 2010. In 2009, certain options which hedge future sales of production were transferred from Level 3 to Level 2. These options were originally included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. Due to increased transparency, this input was considered observable, and we transferred these options to Level 2.

The following tables present a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Year Ended December 31,		
	2010	2009	2008
	Net Energy Derivatives	Net Energy Derivatives	Net Energy Derivatives
	(Millions)		
Beginning balance	$ 1	$ 506	$ (5)
Realized and unrealized gains (losses):			
Included in income (loss) from continuing operations	1	476	96
Included in other comprehensive income (loss)		(329)	478
Purchases, issuances, and settlements	(1)	(479)	(61)
Transfers into Level 3			3

Transfers out of Level 3		(173)	(5)
Ending balance	$ 1	$ 1	$ 506
Unrealized gains included in income from continuing operations relating to instruments held at December 31	$	$	$

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Combined Statement of Operations.

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Notes to Combined Financial Statements (Continued)

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

Fair Value Measurements Using:

	Total Losses for the Years Ended December 31, 2010	2009
	(Millions)	
Impairments:		
Goodwill (see Note 6)	$ 1,003(a)	$
Producing properties and costs of acquired unproved reserves (see Note 6)	678(b)	15(c)
Cost-based investment (see Note 5)		11(d)
	$ 1,681	$ 26

(a) Due to a significant decline in forward natural gas prices across all future production periods during 2010, we determined that we had a trigger event and thus performed an interim impairment assessment of the approximate $1 billion of goodwill related to our domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after- tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined that the implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

(b) As of September 30, 2010, we also believed we had a trigger event as a result of recent significant declines in forward natural gas prices and therefore, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $678 million impairment charge in the

WPX Energy

Notes to Combined Financial Statements (Continued)

third-quarter 2010 as further described below. Fair value measured for these properties at September 30, 2010, was estimated to be approximately $320 million.

$503 million of the impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

$175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent.

(c) Fair value of costs of acquired reserves in the Barnett Shale measured at December 31, 2009, was $22 million. Significant assumption in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas prices (adjusted for locational differences) and an after-tax discount rate of 11 percent.

(d) Fair value measured at March 31, 2009, was zero. This value was based on an other-than-temporary decline in the value of our investment considering the deteriorating financial condition of a Venezuelan corporation in which we own a 4 percent interest.

15. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Combined Balance Sheet approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

Other: Includes margin deposits and customer margin deposits payable for which the amounts reported in the Combined Balance Sheet approximate fair value.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Combined Balance Sheet. See Note 14 for a discussion of valuation of energy derivatives.

Carrying amounts and fair values of our financial instruments were as follows:

	December 31,			
	2010		2009	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
	(Millions)			

Cash and cash equivalents	$ 37	$ 37	$ 34	$ 34
Restricted cash	24	24	19	19
Other	(25)	(25)	(26)	(26)
Net energy derivatives:				
Energy commodity cash flow hedges	266	266	180	180
Other energy derivatives	18	18	(92)	(92)

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Notes to Combined Financial Statements (Continued)

Energy Commodity Derivatives

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We produce, buy and sell natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings.

The following table sets forth the derivative volumes designated as hedges of production volumes as of December 31, 2010:

Commodity	Period	Contract Type	Location	Notional Volume (BBtu)	Weighted Average Price ($/MMBtu)
Natural Gas	2011	Costless Collar	Rockies	16,425	$5.30 - $7.10
Natural Gas	2011	Costless Collar	San Juan	32,850	$5.27 - $7.06
Natural Gas	2011	Costless Collar	MidCon	29,200	$5.10 - $7.00
Natural Gas	2011	Costless Collar	SoCal	10,950	$5.83 - $7.56
Natural Gas	2011	Costless Collar	Appalachia	10,950	$6.50 - $8.14
Natural Gas	2011	Location Swaps	Rockies	27,375	$5.57
Natural Gas	2011	Location Swaps	San Juan	38,325	$5.14
Natural Gas	2011	Location Swaps	MidCon	7,300	$5.22
Natural Gas	2011	Location Swaps	SoCal	7,300	$5.34
Natural Gas	2011	Location Swaps	Appalachia	23,725	$5.59
Natural Gas	2012	Location Swaps	Rockies	25,620	$4.79
Natural Gas	2012	Location Swaps	San Juan	26,535	$5.06
Natural Gas	2012	Location Swaps	MidCon	14,640	$4.74
Natural Gas	2012	Location Swaps	SoCal	9,150	$5.22
Natural Gas	2012	Location Swaps	Appalachia	20,130	$5.93

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Hedges for transportation contracts are designated as cash flow hedges and are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Hedges for storage

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Notes to Combined Financial Statements (Continued)

contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

We also enter into commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties. These legacy natural gas contracts include substantially offsetting positions and have had an insignificant net impact on earnings.

The following table depicts the notional amounts of the net long (short) positions which we did not designate as hedges of our production in our commodity derivatives portfolio as of December 31, 2010. Natural gas is presented in millions of British Thermal Units (MMBtu). All of the Central hub risk realizes in 2011 and 99% of the basis risk realizes in 2011. The net index position includes contracts for the future sale of physical natural gas related to our production. Offsetting these sales are contracts for the future production of physical natural gas related to WPZ s natural gas shrink requirements. These contracts result in minimal commodity price risk exposure and have a value of less than $1 million at December 31, 2010.

Derivative Notional Volumes	**Unit of Measure**	**Central Hub Risk(a)**	**Basis Risk(b)**	**Index Risk(c)**
Not Designated as Hedging Instruments				
Risk Management	MMBtu	(9,077,499)	(20,195,000)	16,586,059
Other	MMBtu	150,400	(14,766,500)	

(a) includes physical and financial derivative transactions that settle against the Henry Hub price;

(b) includes financial derivative transactions priced off the difference in value between the Central Hub and another specific delivery point;

(c) includes physical derivative transactions at an unknown future price, including purchases of 84,583,157 MMBtu primarily on behalf of WPZ and sales of 67,997,098 MMBtu.

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Combined Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	December 31,

	2010		2009	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Millions)			
Designated as hedging instruments	$ 288	$ 22	$ 352	$ 172
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	186	187	505	526
Hedges for storage contracts and other	99	80	237	308
Total derivatives not designated as hedging instruments	285	267	742	834
Total derivatives	$ 573	$ 289	$ 1,094	$ 1,006

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Notes to Combined Financial Statements (Continued)

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in accumulated other comprehensive income (AOCI) or revenues.

	Years Ended December 31, 2010	2009	Classification
	(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$ 505	$ 266	AOCI
Net gain reclassified from *accumulated other comprehensive income (loss)* into income (effective portion)(1)	$ 354	$ 621	Revenues
Gain recognized in income (ineffective portion)	$ 9	$ 4	Revenues

(1) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains associated with our production reflected in oil and gas sales.

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Years Ended December 31, 2010	2009
	(Millions)	
Gas management revenues	$ 47	$ 33
Gas management expenses	28	33
Net gain	$ 19	$

The cash flow impact of our derivative activities is presented in the Combined Statement of Cash Flows as changes in current and noncurrent derivative assets and liabilities.

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from

Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, we have an unsecured credit agreement with certain banks related to hedging activities. We are not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of our domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money position on hedges entered into under the credit agreement.

As of December 31, 2010, we have collateral totaling $8 million, all of which is in the form of letters of credit, posted to derivative counterparties, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $36 million, which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At

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WPX Energy

Notes to Combined Financial Statements (Continued)

December 31, 2009, we had collateral totaling $96 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liabilities position (reflecting master netting arrangements in place with certain counterparties) of $164 million, which included a reduction of $3 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $29 million and $71 million at December 31, 2010 and December 31, 2009, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in other comprehensive income and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of December 31, 2010, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at December 31, 2010, $148 million of net gains (net of income tax provision of $88 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of December 31, 2010. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts receivable

The following table summarizes concentration of receivables (other than as relates to affiliates), net of allowances, by product or service as of December 31:

	2010	2009
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services	$ 272	$ 286
Joint interest owners	83	66
Other	7	7
Total	$ 362	$ 359

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains and Gulf Coast. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues,

WPX Energy

Notes to Combined Financial Statements (Continued)

among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2010 and 2009, we did not incur any significant losses due to counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of December 31, 2010, is summarized as follows.

Counterparty Type	Investment Grade*	Total
	(Millions)	
Gas and electric utilities	$ 7	$ 8
Energy marketers and traders		133
Financial institutions	432	432
	$ 439	573
Credit reserves		
Gross credit exposure from derivatives		$ 573

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2010, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade*	Total
	(Millions)	
Gas and electric utilities	$ 3	$ 3
Financial institutions	317	317
	$ 320	320
Credit reserves		

Net credit exposure from derivatives	$ 320

* We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade.

Our nine largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are eight counterparty positions, representing 81 percent of our net credit exposure from derivatives, associated with our hedging facility (see Note 9). Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

WPX Energy

Notes to Combined Financial Statements (Continued)

At December 31, 2010, the designated collateral agent holds $19 million of collateral support on our behalf under our hedging facility. In addition, we hold collateral support, which may include cash or letters of credit, of $15 million related to our other derivative positions.

Revenues

During 2010, BP Energy Company accounted for 13% of our combined revenues. During 2009, and 2008, there were no customers for which our sales exceeded 10 percent of our combined revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

Net Assets of Operations in Foreign Locations

Net assets of operations in Argentina were $231 million and $208 million as of December 31, 2010 and 2009, respectively.

16. Subsequent Events

Information subsequent to initial date of independent registered public accounting firm report

On June 3, 2011, WPX Energy, Inc., as borrower, entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility Agreement), together with the lenders named therein, and Citibank N.A. (Citi), as administrative agent and swingline lender. Under the terms of the Credit Facility Agreement and subject to certain requirements, WPX Energy, Inc. may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. Borrowings under the Credit Facility Agreement may be used for working capital, acquisitions, capital expenditures and other general corporate purposes.

Under the Credit Facility Agreement, WPX Energy, Inc. may also obtain same day funds by requesting a swingline loan of up to an amount of $125 million from the swingline lender. Interest on swingline loans will be payable at a fluctuating base rate equal to Citi s adjusted base rate plus the applicable margin.

The Credit Facility Agreement will not be effective until the date on which certain conditions listed in the agreement (including, among others, the completion of the initial public offering of WPX Energy, Inc.) have been met or waived; provided that the effective date must be on or before November 30, 2011 or such later date as may be agreed to by WPX Energy, Inc. and the lenders. If the effective date has not occurred by November 30, 2011, the Credit Facility Agreement will automatically terminate unless otherwise extended by WPX Energy, Inc. and the lenders. WPX Energy, Inc. is in the process of seeking an amendment to the Credit Facility Agreement that will eliminate any condition to effectiveness of the Credit Facility Agreement relating to the completion of the initial public offering of WPX Energy, Inc.

Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at the option of WPX Energy, Inc.: (1) a fluctuating base rate equal to Citi s adjusted base rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) Citi s publicly announced base rate, and (iii) one-month LIBOR plus

1.0 percent. WPX Energy, Inc. will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility Agreement. The applicable margin and the commitment fee will be determined by reference to a pricing schedule based on WPX Energy, Inc. s senior unsecured debt ratings.

Under the Credit Facility Agreement, prior to the occurrence of the Investment Grade Date (as defined below), WPX Energy, Inc. will be required to maintain a ratio of PV to debt (each as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. PV is determined as of the end of each fiscal year and reflects the

WPX Energy

Notes to Combined Financial Statements (Continued)

present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves (with a limitation of no more than 35% of proved undeveloped reserves), based on lender projected commodity price assumptions and after giving effect to hedge arrangements. Also, for WPX Energy, Inc. and its consolidated subsidiaries, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. Each of the above ratios will be tested beginning June 30, 2011 at the end of each fiscal quarter. Investment Grade Date means the first date on which WPX Energy, Inc. s long-term senior unsecured debt ratings are BBB- or better by S&P or Baa3 or better by Moody s (without negative outlook or negative watch), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody s.

The Credit Facility Agreement contains customary representations and warranties and affirmative, negative and financial covenants which were made only for the purposes of the Credit Facility Agreement and as of the specific date (or dates) set forth therein, and may be subject to certain limitations as agreed upon by the contracting parties. The covenants limit, among other things, the ability of WPX Energy, Inc. s subsidiaries to incur indebtedness, WPX Energy, Inc. and its material subsidiaries from granting certain liens supporting indebtedness, making investments, loans or advances and entering into certain hedging agreements, WPX Energy, Inc. s ability to merge or consolidate with any person or sell all or substantially all of its assets to any person, enter into certain affiliate transactions, make certain distributions during the continuation of an event of default and allow material changes in the nature of its business. In addition, the representations, warranties and covenants contained in the Credit Facility Agreement may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors. Investors are not third-party beneficiaries of the Credit Facility Agreement and should not rely on the representations, warranties and covenants contained therein, or any descriptions thereof, as characterizations of the actual state of facts or conditions of WPX Energy, Inc.

The Credit Facility Agreement includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to a borrower occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of the loans of the defaulting borrower under the Credit Facility Agreement and exercise other rights and remedies.

As discussed in Note 4, cash receipts and cash expenditures related to the Company s domestic operations have historically been transferred to or from Williams on a regular basis and cleared through unsecured promissory note agreements with Williams. On June 30, 2011, Williams contributed all amounts outstanding on these note agreements to our capital.

During late 2010 and 2011, we incurred approximately $11 million of exploratory drilling costs in connection with a Marcellus Shale well in Columbia County, Pennsylvania. Results have been inconclusive and raise substantial doubt about the economic and operational viability of the well. As a result, the costs associated with this well were expensed as exploratory dry hole costs at September 30, 2011. Further, we assessed the impact of this well on our ability to recover the remaining lease acquisition costs associated with our acreage in Columbia County. During the nine months ended September 30, 2011, we recorded a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage that we do not plan to develop.

On October 18, 2011, Williams announced that its Board of Directors approved a revised reorganization plan that calls for the complete separation of us via a tax-free spin-off of all Williams ownership of us to Williams shareholders by year-end 2011. On October 20, 2011, we filed a Form 10 registration statement with the SEC with respect to this spin-off of our securities. The approval of the revised reorganization plan does not preclude Williams from pursuing the original plan for separation, including an initial public offering, in the event that market conditions become favorable. Williams retains the discretion to determine whether and when to complete these transactions. Also in October 2011, Williams contributed and transferred to WPX Energy, Inc. its investment in certain subsidiaries related to its international exploration and production business, including Apco.

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WPX Energy

Supplemental Oil and Gas Disclosures
(Unaudited)

We have significant oil and gas producing activities primarily in the Rocky Mountain, Northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. This information also excludes our gas management activities.

With the exception of the Results of Operations, the following information includes our Arkoma Basin operations which have been reported as discontinued operations in our combined financial statements. These operations represent approximately one percent or less of our total domestic and international proved reserves for all periods presented.

Capitalized Costs

	As of December 31, 2009			
	Domestic	International	Consolidated Total	Entity s share of international equity method investee
Proved Properties	$ 9,176	$ 180	$ 9,356	$ 187
Unproved properties	945	3	948	
	10,121	183	10,304	187
Accumulated depreciation, depletion and amortization and valuation provisions	(3,213)	(94)	(3,307)	(109)
Net capitalized costs	$ 6,908	$ 89	$ 6,997	$ 78

	As of December 31, 2010			
	Domestic	International	Consolidated Total	Entity s share of international equity method investee
Proved Properties	$ 9,854	$ 213	$ 10,067	$ 220
Unproved properties	2,094	3	2,097	
	11,948	216	12,164	220
Accumulated depreciation, depletion and amortization and valuation provisions	(3,867)	(109)	(3,976)	(129)
Net capitalized costs	$ 8,081	107	$ 8,188	$ 91

Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $312 million and $727 million, net, for 2010 and 2009, respectively.

Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs, and successful exploratory wells.

Unproved properties consist primarily of unproved leasehold costs and costs for acquired unproven reserves.

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

Cost Incurred

	Domestic	International	Entity s share of international equity method investee
		(Millions)	
For the Year Ended December 31, 2008			
Acquisition	$ 543	$	$
Exploration	38	9	7
Development	1,699	27	25
	$ 2,280	$ 36	$ 32
For the Year Ended December 31, 2009			
Acquisition	$ 305	$ 3	$
Exploration	51	3	3
Development	878	19	21
	$ 1,234	$ 25	$ 24
For the Year Ended December 31, 2010			
Acquisition	$ 1,731	$	$
Exploration	22	13	3
Development	988	27	25
	$ 2,741	$ 40	$ 28

Costs incurred include capitalized and expensed items.

Acquisition costs are as follows: The 2010 costs are primarily for additional leasehold in the Williston and Marcellus Basins and include approximately $422 million of proved property values. The 2009 costs are primarily for additional leasehold and reserve acquisitions in the Piceance Basin, and include $85 million of proved property values. The 2008 costs are primarily for additional leasehold and reserve acquisitions in the Piceance and Fort Worth Basins. Included in the 2008 acquisition amounts is $140 million of proved property values and $71 million related to an interest in a portion of acquired assets that a third party subsequently exercised its contractual option to purchase from us, on the same terms and conditions.

Exploration costs include the costs incurred for geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions, and retaining undeveloped leaseholds.

Development costs include costs incurred to gain access to and prepare well locations for drilling and to drill and equip wells in our development basins.

We have classified our step-out drilling and site preparation costs in the Powder River Basin as development, although the immediate offsets are frequently in the dewatering stages in as much as it better reflects the low risk profile of the costs incurred.

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

Results of Operations

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2008			
Revenues:			
Oil and gas revenues	$ 2,810	$ 72	$ 2,882
Other revenues	32		32
Total revenues	2,842	72	2,914
Costs:			
Lease and facility operating	255	17	272
Gathering, processing and transportation	229		229
Taxes other than income	242	12	254
Exploration expenses	31	6	37
Depreciation, depletion and amortization	724	14	738
General and administrative	217	7	224
Gain on sale of international production payment right		(148)	(148)
Other (income) expense	4	2	6
Total costs	1,702	(90)	1,612
Results of operations	1,140	162	1,302
(Provision) benefit for income taxes	(416)	(59)	(475)
Exploration and production net income (loss)	$ 724	$ 103	$ 827

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2009			
Revenues:			
Oil and gas revenues	$ 2,090	$ 78	$ 2,168
Other revenues	39		39
Total revenues	2,129	78	2,207
Costs:			
Lease and facility operating	247	16	263
Gathering, processing and transportation	273		273
Taxes other than income	80	13	93
Exploration expenses	52	2	54
Depreciation, depletion and amortization	870	17	887
Impairment of costs of acquired unproved reserves	15		15
General and administrative	221	9	230
Other (income) expense	33		33
Total costs	1,791	57	1,848
Results of operations	338	21	359
(Provision) benefit for income taxes	(123)	(8)	(131)
Exploration and production net income (loss)	$ 215	$ 13	$ 228

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2010			
Revenues:			
Oil and gas revenues	$ 2,136	$ 89	$ 2,225
Other revenues	40		40
Total revenues	2,176	89	2,265
Costs:			
Lease and facility operating	267	19	286
Gathering, processing and transportation	326		326
Taxes other than income	109	16	125
Exploration expenses	67	6	73
Depreciation, depletion and amortization	858	17	875
Impairment of certain natural gas properties in the Ft. Worth Basin	503		503
Impairment of costs of acquired unproved reserves	175		175
Goodwill impairment	1,003		1,003
General and administrative	225	9	234
Other (income) expense	(19)		(19)
Total costs	3,514	67	3,581
Results of operations	(1,338)	22	(1,316)
(Provision) benefit for income taxes	123	(8)	115
Exploration and production net income (loss)	$ (1,215)	$ 14	$ (1,201)

Amount for all years exclude the equity earnings from the international equity method investee. Equity earnings from this investee were $16 million, $14 million and $16 million in 2010, 2009 and 2008.

Oil and gas revenues consist primarily of natural gas production sold and includes the impact of hedges.

Other revenues consist of activities that are an indirect part of the producing activities. Other expenses in 2009 also include $32 million of expense related to penalties from the early release of drilling rigs.

Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.

Depreciation, depletion and amortization includes depreciation of support equipment. Additionally, 2009 includes $17 million additional depreciation, depletion and amortization as a result of our recalculation of fourth quarter depreciation, depletion and amortization utilizing our year-end reserves which were lower than 2008. The lower reserves are primarily a result of the application of new rules issued by the SEC.

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Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

Proved Reserves

	Domestic (Bcfe)	International(1) (MMBoe)	Entity s share of international equity method investee(2) (MMBoe)	Combined (Bcfe)
For The Year Ended December 31, 2008				
Proved reserves at the beginning of period	4,143	21	15	4,357
Revisions	(220)	1		(208)
Purchases	31			31
Extensions and discoveries	791	2	1	810
Wellhead production	(406)	(2)	(2)	(434)
Proved reserves at the end of period	4,339	22	14	4,556
Proved developed reserves at end of period	2,456	15	10	2,607
For the year ended December 31, 2009				
Proved reserves at the beginning of period	4,339	22	14	4,556
Revisions	(859)	2	1	(841)
Purchases	159			159
Extensions and discoveries	1,051	5	7	1,123
Wellhead production	(435)	(3)	(2)	(466)
Proved reserves at the end of period	4,255	26	20	4,531
Proved developed reserves at end of period	2,387	17	12	2,562
For the year ended December 31, 2010				
Proved reserves at the beginning of period	4,255	26	20	4,531
Revisions	(233)	(2)	1	(242)
Purchases	162			162
Extensions and discoveries	508	4	4	557
Wellhead production	(420)	(3)	(2)	(450)
Proved reserves at the end of period	4,272	25	23	4,558
Proved developed reserves at end of period	2,498	15	14	2,671

(1) Reserves attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(2) Represents Apco s 40.8% interest in reserves of Petrolera Entre Lomas S.A.

The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

Purchases in 2008, 2009 and 2010 include proved developed reserves of 17 Bcfe, 2.4 Bcfe and 42 Bcfe, respectively.

Revisions in 2010 primarily relate to the reclassification of reserves from proved to probable reserves attributable to locations not expected to be developed within five years. A significant portion of the revisions for 2009 are a result of the impact of the new SEC rules. Proved reserves are lower because of the lower 12-month average, first-of-the-month price as compared to the 2008 year-end price, and the revision of proved undeveloped reserve estimates based on new guidance. Approximately one-half of the revisions for 2008 relate to the impact of lower average year-end natural gas prices used in 2008 compared to the 2007.

Extensions and discoveries in 2009 are higher than other years due in part to the expanded definition of oil and gas reserves supported by reliable technology and reasonable certainty used for reserves estimation.

Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Domestic crude oil reserves are insignificant and have been included in the domestic proved reserves on a basis of billion cubic feet equivalents (Bcfe).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves. In 2009, we adopted prescribed accounting revisions associated with oil and gas authoritative guidance. Those revisions include using the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. These revisions are reflected in our 2010 and 2009 amounts. For the years ended December 31, 2010 and 2009, the average domestic natural gas equivalent price, including deductions for gathering, processing and transportation, used in the estimates was $3.78 and $2.76 per MMcfe, respectively. For the year ended December 31, 2008, the average domestic year-end natural gas equivalent price used in the estimates was $4.41 per MMcfe. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

As of December 31, 2009	Domestic	International(1)	Entity s share of international equity method investee(2)
		(Millions)	
Future cash inflows	$ 11,729	$ 664	$ 614
Less:			
Future production costs	3,990	227	228
Future development costs	2,833	83	91
Future income tax provisions	1,404	67	73
Future net cash flows	3,502	287	222
Less 10 percent annual discount for estimated timing of cash flows	(1,789)	(112)	(93)
Standardized measure of discounted future net cash inflows	$ 1,713	$ 175	$ 129

As of December 31, 2010	Domestic	International(1)	Entity s share of international equity method investee(2)
Future cash inflows	$ 16,151	$ 779	$ 787
Less:			
Future production costs	4,927	273	278
Future development costs	2,960	89	92
Future income tax provisions	2,722	98	114
Future net cash flows	5,542	319	303
Less 10 percent annual discount for estimated timing of cash flows	(2,728)	(121)	(117)
Standardized measure of discounted future net cash inflows	$ 2,814	$ 198	$ 186

(1) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(2) Represents Apco s 40.8% interest in Petrolera Entre Lomas S.A.

WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

For the Year Ended December 31, 2008	Domestic	International(1)	Entity s share of international equity method investee(2)
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 4,803	$ 149	$ 115
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(2,091)	(55)	(55)
Net change in prices and production costs	(2,548)	25	34
Extensions, discoveries and improved recovery, less estimated future costs	1,423		
Development costs incurred during year	817	33	25
Changes in estimated future development costs	(724)	(36)	(36)
Purchase of reserves in place, less estimated future costs	55		
Revisions of previous quantity estimates	(395)	50	38
Accretion of discount	714	13	18
Net change in income taxes	1,108	3	
Other	11	(7)	(8)
Net changes	(1,630)	26	16
Standardized measure of discounted future net cash flows end of period	$ 3,173	$ 175	$ 131

WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

For the Year Ended December 31, 2009	**Domestic**	**International(1)**	**Entity s share of international equity method investee(2)**
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 3,173	$ 175	$ 131
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,006)	(49)	(45)
Net change in prices and production costs	(3,310)	(35)	(49)
Extensions, discoveries and improved recovery, less estimated future costs	1,131		
Development costs incurred during year	389	17	21
Changes in estimated future development costs	701	(1)	(3)
Purchase of reserves in place, less estimated future costs	171		
Revisions of previous quantity estimates	(923)	79	88
Accretion of discount	450	21	17
Net change in income taxes	932	(4)	(2)
Other	5	(28)	(29)
Net changes	(1,460)		(2)
Standardized measure of discounted future net cash flows end of period	$ 1,713	$ 175	$ 129

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WPX Energy

Supplemental Oil and Gas Disclosures (Continued)
(Unaudited)

For the Year Ended December 31, 2010	Domestic	International(1)	Entity s share of international equity method investee(2)
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 1,713	$ 175	$ 129
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,446)	(59)	(55)
Net change in prices and production costs	1,921	34	43
Extensions, discoveries and improved recovery, less estimated future costs	724		
Development costs incurred during year	633	26	25
Changes in estimated future development costs	(292)	(12)	(15)
Purchase of reserves in place, less estimated future costs	439	2	
Revisions of previous quantity estimates	(332)	26	63
Accretion of discount	220	22	17
Net change in income taxes	(758)	(13)	(20)
Other	(8)	(3)	(1)
Net changes	1,101	23	57
Standardized measure of discounted future net cash flows end of period	$ 2,814	$ 198	$ 186

(1) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(2) Represents Apco s 40.8% interest in Petrolera Entre Lomas S.A.

In relation to the SEC rules adopted in 2009, we estimated that the domestic standardized measure of discounted future net cash flows in 2009 declined approximately $840 million on a before tax basis and excluding the overall price rule impact. The significant components of this decline included an estimated $640 million decrease included in revisions of previous quantity estimates and a related $430 million decrease included in the net change in prices and production costs, partially offset by a $210 million increase included in extensions, discoveries and improved recovery, less estimated future costs. Additionally, we estimated that a significant portion of the remaining net change in domestic price and production costs is due to the application of the new pricing rules which resulted in the use of lower prices at December 31, 2009, than would have resulted under the previous rules.

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30,000,000 Shares

WPX Energy, Inc.

Common Stock

Prospectus
, 2011

Barclays Capital
Citigroup
J.P. Morgan
BofA Merrill Lynch

Deutsche Bank Securities
Goldman, Sachs & Co.
Morgan Stanley
Wells Fargo Securities

Credit Suisse
RBC Capital Markets
Scotia Capital
UBS Investment Bank
Howard Weil Incorporated

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. ***Other Expenses of Issuance and Distribution.***

The following table sets forth the expenses (other than underwriting compensation expected to be incurred) in connection with this offering. All of such amounts (except the SEC registration fee and FINRA filing fee) are estimated.

SEC registration fee	$ 108,148
FINRA filing fee	75,500
NYSE listing fee	250,000
Printing and engraving expenses	800,000
Legal fees and expenses	1,000,000
Accounting fees and expenses	2,150,000
Transfer agent and Registrar fees	2,000
Miscellaneous	275,000
Total	$ 4,660,648

* To be provided by amendment

Item 14. ***Indemnification of Officers and Directors.***

Our certificate of incorporation provides that a director will not be liable to the corporation or its stockholders for monetary damages for breach of fiduciary duty as a director to the fullest extent that the Delaware General Corporation Law (DGCL) or any other law of the State of Delaware permits. If the DGCL or any other law of the State of Delaware is amended to authorize the further elimination or limitation of the liability of directors, then the liability of a director will be limited to the fullest extent permitted by the amended DGCL or other law, as applicable.

We are empowered by Section 145 of the DGCL, subject to the procedures and limitations stated therein, to indemnify any person against expenses (including attorneys fees), judgments, fines, and amounts paid in settlement actually and reasonably incurred by them in connection with any threatened, pending, or completed action, suit, or proceeding in which such person is made party by reason of their being or having been a director, officer, employee, or agent of the Company. The statute provides that indemnification pursuant to its provisions is not exclusive of other rights of indemnification to which a person may be entitled under any bylaw, agreement, vote of stockholders or disinterested directors, or otherwise. Our bylaws provide for indemnification by us of our directors and officers to the fullest extent permitted by the DGCL.

Williams currently maintains, and after the spin-off, the Company will maintain, policies of insurance under which our directors and officers are insured, within the limits and subject to the limitations of the policies, against certain expenses in connection with the defense of actions, suits, or proceedings, and certain liabilities which might be imposed as a result of such actions, suits or proceedings, to which they are parties by reason of being or having been such directors or officers.

Item 15. ***Recent Sales of Unregistered Securities.***

Except for the issuance of shares to Williams, we have not issued any securities in unregistered transactions. The issuance of shares to Williams was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) thereof.

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Item 16. ***Exhibits and Financial Statement Schedules.***

(a) *Exhibits*

A list of exhibits filed as part of this registration statement is set forth in the Exhibit Index, which is incorporated herein by reference.

(b) *Financial Statement Schedules*

Schedule II Valuation and Qualifying Accounts for the three years ended December 31, 2010, 2009 and 2008

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	Charged (Credited) to Costs and Expenses	Other (Millions)	Deductions	Ending Balance
2010:					
Allowance for doubtful accounts accounts and notes receivable(a)	$ 19	$ (3)	$	$	$ 16
Price-risk management credit reserves liabilities(b)	(3)	3(d)			
2009:					
Allowance for doubtful accounts accounts and notes receivable(a)	25	3		(9)(c)	19
Price-risk management credit reserves assets(a)	6	(3)(d)	(3)(e)		
Price-risk management credit reserves liabilities(b)	(15)	12(d)			(3)
2008:					
Allowance for doubtful accounts accounts and notes receivable(a)	14	12		(1)(c)	25
Price-risk management credit reserves assets(a)	1	1(d)	4(e)		6
Price-risk management credit reserves liabilities(b)		(16)(d)	1(e)		(15)

(a) Deducted from related assets.

(b) Deducted from related liabilities.

(c) Represents recoveries of balances previously written off.

(d) Included in revenues.

(e) Included in accumulated other comprehensive income (loss).

Item 17. ***Undertakings.***

The undersigned registrant hereby undertakes that:

(1) The undersigned will provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

(2) For purposes of determining any liability under the Securities Act of 1933, as amended, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1)

or (4) or 497(h) under the Securities Act of 1933, as amended, shall be deemed to be part of this registration statement as of the time it was declared effective.

(3) For the purpose of determining any liability under the Securities Act of 1933, as amended, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

Insofar as indemnification for liabilities arising under the Securities Act of 1933, as amended, may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933, as amended, and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act of 1933, as amended, and will be governed by the final adjudication of such issue.

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Signatures

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Tulsa, State of Oklahoma, on October 28, 2011.

WPX ENERGY, INC.
(Registrant)

By: /s/ Ralph A. Hill
Ralph A. Hill
Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed below by the following persons in the capacities and on the dates indicated:

Date: October 28, 2011	By: /s/ Ralph A. Hill Ralph A. Hill, Chief Executive Officer(Principal Executive Officer)
Date: October 28, 2011	By: /s/ Donald R. Chappel Donald R. Chappel, Chief Financial Officer (Principal Financial Officer)
Date: October 28, 2011	By: /s/ Ted T. Timmermans Ted T. Timmermans, Chief Accounting Officer (Principal Accounting Officer)
Date: October 28, 2011	By: /s/ Alan S. Armstrong Alan S. Armstrong, Chairman of the Board

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EXHIBIT INDEX

Exhibit No.	Description
1.1	Form of Underwriting Agreement
(2.1)	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC
3.1	Form of Amended and Restated Certificate of Incorporation of WPX Energy, Inc.
3.2	Form of Amended and Restated Bylaws of WPX Energy, Inc.
4.1	Form of Specimen Common Stock Certificate
5.1	Form of Opinion of Gibson, Dunn & Crutcher LLP
10.1	Form of Separation and Distribution Agreement
(10.2)	Form of Administrative Services Agreement
(10.3)	Form of Transition Services Agreement
10.4	Form of Tax Sharing Agreement
10.5	Form of Registration Rights Agreement
(10.6)	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender
(10.7)#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011
(10.8)	Form of WPX Energy, Inc. 2011 Incentive Plan
(10.9)	Form of WPX Energy, Inc. 2011 Employee Stock Purchase Plan
(21.1)	List of Subsidiaries
23.1	Consent of Gibson, Dunn & Crutcher LLP (included in Exhibit 5.1)
23.2	Consent of Ernst & Young LLP
23.3	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.4	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, Ltd.
23.5	Consent of Independent Petroleum Engineers, Ralph E. Davis Associates, Inc.
(24.1)	Powers of Attorney (included on signature page of the initial registration statement)
(99.1)	Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
(99.2)	Report of Independent Petroleum Engineers and Geologists, Miller and Lents, Ltd.
(99.3)	Report of Independent Petroleum Engineers, Ralph E. Davis Associates, Inc.
(99.4)	Consent of Prospective Director, George A. Lorch
(99.5)	Consent of Prospective Director, William G. Lowrie
99.6	Consent of Prospective Director, Donald R. Chappel
99.7	Consent of Prospective Director, Ralph A. Hill

( ) Previously filed with this registration statement

\# Certain portions have been omitted pursuant to a pending confidential treatment request. Omitted information has been filed separately with the SEC.