WPX ENERGY, INC.
Form S-4
April 24, 2012
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As filed with the Securities and Exchange Commission on April 24, 2012

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-4

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

WPX ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

One Williams Center

Tulsa, Oklahoma 74172-0172

(800) 945-5426

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

James J. Bender

Senior Vice President and General Counsel

Stephen E. Brilz

Vice President and Secretary

One Williams Center, Suite 4900

Tulsa, Oklahoma 74172-0172

(855) 979-2012

(Name, address, including zip code, and telephone number, including area code, of agent for service)

With a copy to:

Richard M. Russo

Robyn E. Zolman

Gibson, Dunn & Crutcher LLP

1801 California Street, Suite 4200

Denver, CO 80202-2642

(303) 298-5700

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

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. ¨

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. ¨

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. ¨

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x	Smaller reporting company	¨

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issue Tender Offer) ¨

Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer) ¨

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	**Amount to be registered**	**Proposed maximum offering price per unit(1)**	**Proposed maximum aggregate offering price(1)**	**Amount of registration fee(2)**
5.250% Senior Notes due 2017	$400,000,000	100%	$400,000,000	$45,840
6.000% Senior Notes due 2022	$1,100,000,000	100%	$1,100,000,000	$126,060

(1) Exclusive of accrued interest, if any, and estimated solely for the purpose of calculating the registration fee in accordance with Rule 457(f) under the Securities Act of 1933, as amended.

(2) The registration fee has been satisfied in part by applying, pursuant to Rule 457(p) under the Securities Act, $21,072.16 of the filing fee previously paid by WPX Energy, Inc. in connection with its Registration Statement on Form S-1 (SEC File No. 333-173808), initially filed on April 29, 2011.

The registrants hereby amend this registration statement on such date or dates as may be necessary to delay its effective date until the registrants 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, as amended, 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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The information in this prospectus is not complete and may be changed. We may not complete the exchange offer and issue these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated April 24, 2012

PROSPECTUS

$1,500,000,000

WPX ENERGY, INC.

Offer to Exchange

$400,000,000 5.250% Senior Notes due 2017

that have been registered under the Securities Act of 1933

for all outstanding 5.250% Senior Notes due 2017

(CUSIP Nos. 9821BAA1 and U46031AA5)

and

$1,100,000,000 6.000% Senior Notes due 2022

that have been registered under the Securities Act of 1933

for all outstanding 6.000% Senior Notes due 2022

(CUSIP Nos. 98212BAB9 and U46031AB3)

This exchange offer will expire at 5:00 p.m., New York City time,

on , 2012, unless extended.

We are offering to exchange our 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022, which have been registered under the Securities Act of 1933, as amended (the Securities Act) and which we refer to in this prospectus collectively as the exchange notes, for any and all of our 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022, respectively, issued on November 14, 2011, which we refer to in this prospectus collectively as the outstanding notes. The term notes refers to both the outstanding notes and the exchange notes. We refer to the offer to exchange the exchange notes for the outstanding notes as the exchange offer in this prospectus.

The Exchange Notes:

The terms of the registered exchange notes to be issued in the exchange offer are substantially identical to the terms of the outstanding notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding notes will not apply to the exchange notes.

We are offering the exchange notes pursuant to a registration rights agreement that we entered into in connection with the issuance of the outstanding notes.

The 5.250% Senior Notes due 2017 offered hereby (the 2017 notes) will bear interest at the rate of 5.250% per year, payable semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2012. The 6.000% Senior Notes due 2022 offered hereby (the 2022 notes) will bear interest at the rate of 6.000% per year, payable semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2012.

Material Terms of the Exchange Offer:

The exchange offer expires at 5:00 p.m., New York City time, on , 2012, unless extended.

Upon expiration of the exchange offer, all outstanding 5.250% Senior Notes due 2017 that are validly tendered and not withdrawn will be exchanged for an equal principal amount of the 2017 notes, and all outstanding 6.000% Senior Notes due 2022 that are validly tendered and not withdrawn will be exchanged for an equal principal amount of the 2022 notes.

You may withdraw tendered outstanding notes at any time prior to the expiration of the exchange offer.

The exchange offer is not subject to any minimum tender condition, but is subject to customary conditions.

The exchange of the exchange notes for outstanding notes will not be a taxable exchange for U.S. federal income tax purposes.

Each broker-dealer that receives exchange notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act of 1933, as amended, in connection with any resale of such exchange notes. The letter of transmittal accompanying this prospectus states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange notes received in exchange for outstanding notes where such exchange notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that for a period of 180 days after the expiration of the exchange offer, we will make this prospectus available to any broker-dealer for use in any such resale. See Plan of Distribution.

There is no existing public market for the outstanding notes or the exchange notes. We do not intend to list the exchange notes on any securities exchange or quotation system.

See Risk Factors beginning on page 9.

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

Prospectus dated , 2012

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You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with any information or represent anything about us, our financial results, or this offering that is not contained in this prospectus. If given or made, any such other information or representation should not be relied upon as having been authorized by us. We are not making an offer to sell these exchange notes in any jurisdiction where the offer or sale is not permitted.

The information in this prospectus is applicable only as of the date on its cover, and may change after that date. The information in any document incorporated by reference in this prospectus is applicable only as of the date of any such document. For any time after the cover date of this prospectus, we do not represent our affairs are the same as described or the information in this prospectus is correct nor do we imply those things by delivering this prospectus or issuing exchange notes to you.

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FORWARD-LOOKING STATEMENTS

Certain matters discussed 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, might, goals, objectives, targets, planned, potential, projects, scheduled, will or other similar expressions. These forward-lookin based 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;

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- Our exposure to the credit risks 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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WHERE YOU CAN FIND MORE INFORMATION

WPX Energy, Inc. has filed a registration statement with the Securities and Exchange Commission (the Commission or the SEC) on Form S-4 to register the exchange offer contemplated in this prospectus. This prospectus is part of that registration statement. As allowed by the Commission s rules, this prospectus does not contain all the information found in the registration statement or the exhibits to the registration statement. This prospectus contains summaries of the material terms and provisions of certain documents and in each instance we refer you to the copy of such document filed as an exhibit to the registration statement.

We have not authorized anyone to give any information or make any representation about us that is different from or in addition to, that contained in this prospectus. Therefore, if anyone does give you information of this sort, you should not rely on it as authorized by us. If you are in a jurisdiction where offers to sell, or solicitations of offers to purchase, the securities offered by this prospectus are unlawful, or if you are a person to whom it is unlawful to direct these types of activities, then the offer presented in this prospectus does not extend to you. Neither the delivery of this prospectus, nor any sale made hereunder, shall under any circumstances create any implication that there has been no change in our affairs since the date on the front cover of this prospectus.

WPX Energy, Inc. is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and in accordance therewith files annual, quarterly and other reports and information with the Commission.

The registration statement (including the exhibits and schedules thereto) and the periodic reports and other information filed by WPX Energy, Inc. with the Commission may be inspected and copied at the Commission s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the Commission at 1-800-SEC-0330 for further information on the Public Reference Room. Such information may also be accessed electronically by means of the Commission s homepage on the Internet at http://www.sec.gov.

You may also obtain this information without charge by writing or telephoning us at the following address and telephone number:

WPX Energy, Inc.

One Williams Center

Tulsa, OK 74172-0172

(918) 573-9360

Attn: Investor Relations

To ensure timely delivery, you must request this information no later than five business days before the expiration of the exchange offer.

INDUSTRY AND MARKET DATA

In this prospectus, we rely on and refer to information and statistics regarding our industry. We obtained this market data from independent industry publications or other publicly available information. Although we believe that these sources are reliable, we have not independently verified and do not guarantee the accuracy or completeness of this information.

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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, condensate or NGLs 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.

Mbbls/d means one thousand barrels per day.

Mboe/d means one 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, condensate or NGLs 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.

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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, condensate or NGLs 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, condensate or NGLs 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.

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PROSPECTUS SUMMARY

This summary highlights some of the information contained or incorporated by reference in this prospectus. It does not contain all of the information that you should consider before making a decision to invest in the notes. 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 before making an investment decision. Some of the statements in this summary constitute forward-looking statements. See Forward-Looking Statements.

Except where otherwise indicated, (1) WPX (which includes WPX Energy, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as we, us or our. We also sometimes refer to WPX as the Company or WPX Energy, and (2) all references to Williams refer to The Williams Companies, Inc. and its subsidiaries.

WPX Energy, Inc.

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 reserves 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 an approximate 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. Our international interests make up approximately four 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. Our proved reserves at December 31, 2011 were 5,265 Bcfe, comprised of 5,070 Bcfe in domestic reserves and 195 Bcfe in net international reserves. Our total reserves reflect a mix of 77.4 percent natural gas, 15.4 percent NGLs and 7.2 percent crude oil. During 2011, we replaced our domestic production for all commodities at a rate of 188 percent. For liquids alone, we replaced 488 percent of our crude and NGL production. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

Principal Executive Offices

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is (855) 979-2012. Our website address is 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.

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THE EXCHANGE OFFER

The summary below describes the principal terms and conditions of the exchange offer. Certain of these terms and conditions are subject to important limitations and exceptions. The section of this prospectus entitled Description of the Notes contains a more detailed description of the terms and conditions.

The Exchange Offer	$400,000,000 of 2017 notes registered under the Securities Act are being offered in exchange for the same principal amount of our outstanding 5.250% Senior Notes due 2017 and $1,100,000,000 of 2022 notes registered under the Securities Act are being offered in exchange for the same principal amount of our outstanding 6.000% Senior Notes due 2022. Terms of the exchange notes and the outstanding notes are substantially identical, except that the transfer restrictions, registration rights, and rights to increased interest in addition to the stated interest rate on the outstanding notes (Additional Interest) applicable to the outstanding notes will not apply to the exchange notes. You may tender outstanding notes for exchange in whole or in part in any integral multiple of $1,000, subject to a minimum exchange of $2,000; provided, that any untendered portion of an outstanding note must be in a minimum principal amount of $2,000. We are undertaking the exchange offer to satisfy our obligations under the registration rights agreement relating to the outstanding notes. For a description of the procedures for tendering the outstanding notes. See The Exchange Offer How to Tender Outstanding Notes for Exchange.
	To exchange your outstanding notes for exchange notes, you must properly tender them before the expiration of the exchange offer. Upon expiration of the exchange offer, your rights under the registration rights agreement pertaining to the outstanding notes will terminate, except under limited circumstances.
Expiration Time	The exchange offer expires at 5:00 p.m., New York City time on , 2012, unless the exchange offer is extended. See The Exchange Offer Terms of the Exchange Offer; Expiration Time.
Interest on Outstanding Notes Exchanged in the Exchange Offer	Holders whose outstanding notes are exchanged for exchange notes will not receive a payment in respect of interest accrued but unpaid on such outstanding notes from the original issue date of the outstanding notes or the most recent interest payment date up to but excluding the settlement date. Instead, interest on the exchange notes received in exchange for such outstanding notes will (i) accrue from the last date on which interest was paid on such outstanding notes or, if no interest has been paid on such outstanding notes, from the original issue date of such outstanding notes and (ii) accrue at the same rate as and be payable on the same dates as interest was payable on such outstanding notes. However, if any interest payment occurs prior to the settlement date on any outstanding notes already tendered for exchange in the exchange offer, the holder of such outstanding notes will be entitled to receive such interest payment.
Conditions to the Exchange Offer	The exchange offer is subject to customary conditions (see The Exchange Offer Conditions to the Exchange Offer), some of which

	we may waive in our sole discretion. The exchange offer is not conditioned upon any minimum principal amount of outstanding notes being tendered for exchange.
How to Tender Outstanding Notes for Exchange	You must tender your outstanding notes through book-entry transfer in accordance with The Depository Trust Company s Automated Tender Offer Program, known as ATOP. If you wish to accept the exchange offer, you must arrange for The Depository Trust Company to transmit to the exchange agent certain required information, including an agent s message forming part of a book-entry transfer in which you agree to be bound by the terms of the letter of transmittal, and transfer the outstanding notes being tendered into the exchange agent s account at The Depository Trust Company.
Guaranteed Delivery Procedures	If you wish to tender your outstanding notes and the procedures for book-entry transfer cannot be completed by the expiration time, you may tender your outstanding notes according to the guaranteed delivery procedures described in The Exchange Offer Guaranteed Delivery Procedures.
Special Procedures for Beneficial Owners	If you beneficially own outstanding notes registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your outstanding notes in the exchange offer, you should contact the registered holder promptly and instruct it to tender on your behalf. See The Exchange Offer How to Tender Outstanding Notes for Exchange.
Withdrawal of Tenders	You may withdraw your tender of outstanding notes at any time prior to the expiration time by delivering a notice of withdrawal to the exchange agent in conformity with the procedures discussed under The Exchange Offer Withdrawal Rights.
Acceptance of Outstanding Notes and Delivery of Exchange Notes	Upon consummation of the exchange offer, we will accept any and all outstanding notes that are properly tendered in the exchange offer and not withdrawn prior to the expiration time. The exchange notes issued pursuant to the exchange offer will be delivered promptly following the expiration time. See The Exchange Offer Terms of the Exchange Offer; Expiration Time.
Registration Rights Agreement	We are making the exchange offer pursuant to the registration rights agreement that we entered into on November 14, 2011, with the initial purchasers of the outstanding notes. As a result of making and consummating this exchange offer, we will have fulfilled our obligations under the registration rights agreement with respect to the registration of securities, subject to certain limited exceptions. If you do not tender your outstanding notes in the exchange offer, you will not have any further registration rights under the registration rights

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agreement or otherwise unless you were not eligible to participate in the exchange offer or do not receive freely tradable exchange notes in the exchange offer.

Resales of Exchange Notes	We believe the exchange notes issued in the exchange offer may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act, provided that:

- you are not an affiliate of ours;
- the exchange notes you receive pursuant to the exchange offer are being acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person to participate in the distribution of the exchange notes issued to you in the exchange offer;
- if you are not a broker-dealer, you are not engaged in, and do not intend to engage in, a distribution of the exchange notes issued in the exchange offer; and
- if you are a broker-dealer, you will receive the exchange notes for your own account, the outstanding notes were acquired by you as a result of market-making or other trading activities, and you will deliver a prospectus when you resell or transfer any exchange notes issued in the exchange offer. See Plan of Distribution for a description of the prospectus delivery obligations of broker dealers in the exchange offer.

If you do not meet these requirements, your resale of the exchange notes must comply with the registration and prospectus delivery requirements of the Securities Act.

Our belief is based on interpretations by the Commission staff, as set forth in no-action letters issued to third parties. The Commission staff has not considered this exchange offer in the context of a no-action letter, and we cannot assure you that the Commission staff would make a similar determination with respect to this exchange offer.

If our belief is not accurate and you transfer an exchange note without delivering a prospectus meeting the requirements of the federal securities laws or without an exemption from these laws, you may incur liability under the federal securities laws. We do not and will not assume, or indemnify you against, this liability.

See The Exchange Offer Consequences of Exchanging Outstanding Notes.

Consequences of Failure to Exchange Your Outstanding Notes	If you do not exchange your outstanding notes for exchange notes in the exchange offer, your outstanding notes will continue to be subject

	to the restrictions on transfer provided in the legend on the outstanding notes and in the indenture governing the notes. In general, the outstanding notes may not be offered or sold unless registered or sold in a transaction exempt from registration under the Securities Act and applicable state securities laws. Accordingly, the trading market for your untendered outstanding notes could be adversely affected.
Exchange Agent	The exchange agent for the exchange offer is The Bank of New York Mellon Trust Company, N.A. For additional information, see The Exchange Offer The Exchange Agent and the accompanying letter of transmittal.
Certain Federal Income Tax Considerations	The exchange of your outstanding notes for exchange notes will not be a taxable exchange for United States federal income tax purposes. **You should consult your own tax advisor as to the tax consequences to you of the exchange offer, as well as tax consequences of the ownership and disposition of the exchange notes.** For additional information, see Material United States Federal Income Tax Considerations.

Summary of the Terms of the Exchange Notes

The terms of the exchange notes are substantially identical to the outstanding notes, except the transfer restrictions, registration rights and Additional Interest provisions applicable to the outstanding notes will not apply to the exchange notes. The following is a summary of the principal terms of the exchange notes. A more detailed description is contained in the section entitled Description of the Notes in this prospectus.

Issuer	WPX Energy, Inc.
Notes Offered	$1,500,000,000 aggregate principal amount of Senior Notes consisting of:
	$400,000,000 aggregate principal amount of 2017 notes; and
	$1,100,000,000 aggregate principal amount of 2022 notes.
Maturity Date	The 2017 notes will mature on January 15, 2017.
	The 2022 notes will mature on January 15, 2022.
Interest Rates	The 2017 notes will bear interest at a rate of 5.250% per year.
	The 2022 notes will bear interest at a rate of 6.000% per year.
Interest	The 2017 notes will pay interest semi-annually in cash in arrears on January 15 and July 15 of each year. The 2022 notes will pay interest semi-annually in cash in arrears on January 15 and July 15 of each year.
	Holders whose outstanding notes are exchanged for exchange notes will not receive a payment in respect of interest accrued but unpaid on such outstanding notes from the original issue date of the outstanding notes or the most recent interest payment date up to but excluding the settlement date. Instead, interest on the exchange notes received in exchange for such outstanding notes will (i) accrue from the last date on which interest was paid on such outstanding notes or, if no interest has been paid on such outstanding notes, from the original issue date of such outstanding notes and (ii) accrue at the same rate as and be payable on the same dates as interest was payable on such outstanding notes. However, if any interest payment occurs prior to the settlement date on any outstanding notes already tendered for exchange in the exchange offer, the holder of such outstanding notes will be entitled to receive such interest payment.
Optional Redemption	We have the option, prior to maturity, in the case of the 2017 notes, and prior to October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes), in the case of the 2022 notes, to redeem all or a portion of the notes of the

applicable series at any time at a redemption price equal to the greater of (i) 100% of their principal amount and (ii) the discounted present value of 100% of their principal amount and remaining scheduled interest payments, in either case plus accrued and unpaid interest to the redemption date, as described under Description of the Notes Optional Redemption.

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	We also have the option at any time on or after October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes), to redeem the 2022 notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus accrued and unpaid interest thereon to the redemption date. See Description of the Notes Optional Redemption.
Change of Control	If we experience a change of control (as defined in the indenture governing the notes) accompanied by a rating decline with respect to a series of notes, we must offer to repurchase the notes of such series at 101% of their principal amount, plus accrued and unpaid interest. See Description of the Notes Change of Control.
Ranking	The exchange notes will be our senior unsecured indebtedness. Your right to payment under the exchange notes will be equal in right of payment with all of our future senior unsecured indebtedness. The exchange notes will be effectively subordinated to all of our future secured indebtedness to the extent of the value of the assets securing such indebtedness and will be structurally subordinated to all existing and future indebtedness and other liabilities of our subsidiaries. The exchange notes will rank senior to all of our future subordinated indebtedness.
Certain Covenants	We will issue the exchange notes under an indenture, to be dated as of November 14, 2011, between us and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture will contain limitations on, among other things: the grant of liens on our assets to secure certain types of indebtedness; and certain mergers or consolidations and transfers of assets. These covenants are subject to significant exceptions. See Description of the Notes Certain Covenants.
Use of Proceeds	We will not receive any cash proceeds from the issuance of the exchange notes offered by this prospectus.
Form and Denomination	Each series of the exchange notes will be represented by one or more global notes. The global notes will be deposited with the trustee, as custodian for The Depository Trust Company, or DTC. Ownership of beneficial interests in the global notes will be shown on, and transfers of such interests will be effected only through, records maintained in book-entry form by DTC and its direct and indirect participants, including in the case of notes sold under Regulation S, the depositaries for Clearstream Banking S.A., Luxembourg, or Euroclear Bank S.A./N.V., as operator of the Euroclear System.

The exchange notes will be issued in minimum denominations of $2,000 and in integral multiples of $1,000 in excess thereof.

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Trustee	The Bank of New York Mellon Trust Company, N.A.
Governing Law	New York.
Risk Factors	**Investment in the exchange notes involves certain risks. You should carefully consider the information under Risk Factors and all other information included in this prospectus before investing in the exchange notes.**

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RISK FACTORS

An investment in the exchange notes involves risks. You should carefully consider the risks described below as well as the other information contained in this prospectus prior to making an investment decision. The risks described in this prospectus are not the only ones we may face. There may be additional risks and uncertainties not currently known to us or that we may currently deem immaterial in addition to those outlined below, which could impair our financial position and results of operations. If any of the following risks occurs, our business, financial condition and results of operations could be materially adversely affected. In such case, you may lose all or part of your original investment. As used below, the term notes refers to both the outstanding notes and the exchange notes.

Risks Relating to Our Business

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

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;

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- Adverse weather conditions, such as floods or blizzards;
- Title and lease related problems;
- Limitations in the market for natural gas and oil;
- 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 60 percent of our drilling capital during 2012 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 annual and interim assessments for impairments of our proved properties and due to significant declines in forward natural gas prices, we recorded impairments of capitalized costs of certain natural gas properties of $547 million in 2011 and $678 million in 2010. In addition to those long-lived assets for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included 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 consolidated financial statements. For the other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately eight percent could be at risk for impairment if forward prices across all future periods decline by approximately 12 to 14 percent, on average, as compared to the forward prices at December 31, 2011. A substantial portion of the remaining carrying value of these other assets (primarily related to assets in the Piceance basin) could be at risk for impairment if forward prices across all future periods decline by at least 24 percent, on average, as compared to the prices at December 31, 2011. 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.

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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 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, 2011 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. In accordance with SEC requirements, 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.

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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 we do not extend our leases and 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 under our $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility) 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.

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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, 2011, we were not the operator of approximately 14 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 commodity price risk management and measurement systems and economic 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

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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 derivatives 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

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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.

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.

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We currently maintain excess liability insurance that covers us, 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.

Although we maintain property insurance on certain physical assets that we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets. 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. 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 in 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.

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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.

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 certain affiliate transactions. In addition, our Credit Facility contains financial covenants and other limitations with which we will need to comply and which may limit our ability to borrow under the facility. Similarly, the indenture governing the Notes restricts 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.

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.

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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 U.S. Environmental Protection Agency (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 Clean Air Act (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 of 1990 (OPA), 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 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.

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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

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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

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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, or changing the timing of, certain 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 2013, released by the White House on February 13, 2012, is the elimination of, or changing the timing 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. 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, or change the timing of, certain tax deductions that are currently available with respect to oil and gas exploration and development. Changes to 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.

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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.

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.

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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.

Risks Related to Our Recent Separation from Williams

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

We may not realize the benefits that we anticipated 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.

Our historical 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 financial information that we have included in this prospectus 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. 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 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, the provision of letters of credit in lieu of Williams guarantees to support certain contracts and increased costs associated with the SEC reporting and the NYSE requirements. Therefore, our historical 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 Consolidated 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.

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. We are now obligated to file with the SEC annual and quarterly information and other reports that are specified in Section 13 and other sections of the Exchange Act. We are 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 are 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 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.

We will continue to depend on Williams to provide us with certain services for our business; the services that Williams provides to us 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 transition services required by us for the operation of our business are currently provided by Williams and its subsidiaries, including services related to finance and accounting, payroll and human resources administration, information technology, real estate and facilities management, sourcing and procurement, mail, print and other office services. We have entered into agreements with Williams related to the separation of our business operations from Williams, including a transition services agreement. The services provided under the transition services agreement commenced on the December 31, 2011 (the Distribution Date) and will 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 transition services agreement to facilitate the efficient operation of our business in our transition to a stand alone public company. We are, as a result, depending on Williams for services. 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 the transition services agreement, 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 receive from Williams under the transition services agreement. 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.

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. 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) 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.

We may increase our debt or raise additional capital in the future, which could affect our financial health, and may decrease our profitability.

We may increase our debt or raise additional capital in the future, subject to restrictions in our debt agreements. If our cash flow from operations is less than we anticipate, or if our cash requirements are more than we expect, we may require more financing. However, debt or equity financing may not be available to us on terms acceptable to us, if at all. If we incur additional debt or raise equity through the issuance of our preferred stock, the terms of the debt or our preferred stock issued may give the holders rights, preferences and privileges senior to those of holders of our common stock, particularly in the event of liquidation. The terms of the debt may also impose additional and more stringent restrictions on our operations than we currently have. If we are unable to raise additional capital when needed, it could affect our financial health, which could negatively affect your investment in us.

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 agreed to take reasonable action or reasonably refrain from taking action to ensure that the spin-off qualifies for tax-free status under section 355 and section 368(a)(1)(D) of the Internal Revenue Code of 1986 (the Code) (unless the Internal Revenue Service (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). We also agreed to various other covenants in the tax sharing agreement intended to ensure the tax-free status of the spin-off. These covenants restrict our ability to sell assets outside the ordinary course of business, to issue or sell additional common stock (including securities convertible into our common stock), or to enter into certain other corporate transactions. For example, we may not enter into any

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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 transactions considered related to the spin-off.

Further, under the tax sharing agreement, we are required to indemnify Williams against certain tax-related liabilities that may be incurred by Williams (including any of its subsidiaries) relating to the spin-off, 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 the tax opinion that Williams received as a condition to the spin-off. 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 any tax periods ending on or before the spin-off, 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 generally 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 after taking into account any prior related payments or credits. In addition, Williams will effectively control all of our U.S. tax decisions in connection with any Williams 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 its tax returns, to prepare and file all consolidated, combined or unitary income tax returns in which we are included (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.

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 with respect to periods prior to the spin-off in which we were a member of Williams consolidated group. Similar principles may apply for foreign, state or local income tax purposes where we were included in combined, consolidated or unitary returns with Williams or its subsidiaries for foreign, state or local income tax purposes.

If 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 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 was conditioned on Williams receipt of an opinion of its outside tax advisor reasonably acceptable to the Williams board of directors to the effect that the spin-off would not result in the recognition, for U.S. federal income tax purposes, of income, gain or loss to Williams, and Williams stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of fractional

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shares of WPX common stock that such stockholders would otherwise receive in the distribution. Williams received an opinion from its outside tax advisor to such effect. In addition, Williams received a private letter ruling from the IRS in which the IRS made various rulings, including that the spin-off will not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams and Williams stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of fractional shares of WPX common stock that such stockholders would otherwise receive in the distribution. The private letter ruling and opinion relied 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 or the opinion of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinion of Williams tax advisor, the IRS could conclude upon audit that the spin-off is taxable in full or in part 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, we could incur significant indemnification liabilities provided for in the 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 agreed 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 the spin-off or are not expressly assumed by us under our agreements with Williams. 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, or who hold options to acquire common stock of Williams or other Williams equity-based awards, 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, 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.

The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. Under these laws, if a court in a lawsuit by an unpaid creditor or an entity vested with the power of such creditor (including without limitation a trustee or debtor-in-possession in a bankruptcy by us or Williams or any of our respective

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subsidiaries) were to determine that Williams or any of its subsidiaries did not receive fair consideration or reasonably equivalent value for distributing our common stock or taking other action as part of the spin-off, or that we or any of our subsidiaries did not receive fair consideration or reasonably equivalent value for incurring indebtedness, including the new debt incurred by us in connection with the spin-off, transferring assets or taking other action as part of the spin-off and, at the time of such action, we, Williams or any of our respective subsidiaries (i) was insolvent or would be rendered insolvent, (ii) had unreasonably small capital with which to carry on its business and all business in which it intended to engage or (iii) intended to incur, or believed it would incur, debts beyond its ability to repay such debts as they would mature, then such court could void the spin-off as a constructive fraudulent transfer. If such court made this determination, the court could impose a number of different remedies, including without limitation, voiding our liens and claims against Williams, or providing Williams with a claim for money damages against us in an amount equal to the difference between the consideration received by Williams and the fair market value of our company at the time of the spin-off.

The measure of insolvency for purposes of the fraudulent conveyance laws will vary depending on which jurisdiction s law is applied. Generally, however, an entity would be considered insolvent if the present fair saleable value of its assets is less than (i) the amount of its liabilities (including contingent liabilities) or (ii) the amount that will be required to pay its probable liabilities on its existing debts as they become absolute and mature. No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Williams or any of our respective subsidiaries were solvent at the time of or after giving effect to the spin-off, including the distribution of our common stock.

Under the separation and distribution agreement, each of Williams and we are responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to Williams, particularly if Williams were to refuse or were unable to pay or perform the subject allocated obligations.

Risk Factors Related to the Exchange Offer

An active trading market may not develop for the exchange notes.

There is no existing public market for the exchange notes. We do not intend to have the exchange notes listed on a national securities exchange or to arrange for quotation on any automated dealer quotation systems. Therefore, we cannot assure you as to the development or liquidity of any trading market for the exchange notes. The liquidity of any market for the exchange notes will depend on a number of factors, including:

- the number of holders of exchange notes;
- our operating performance and financial condition;
- the market for similar securities;
- the interest of securities dealers in making a market in the exchange notes; and
- prevailing interest rates.

An active trading market may not develop or be maintained for the exchange notes. If an active market does not develop or is not maintained, the market price and liquidity of the exchange notes may be adversely affected, and you may not be able to sell your exchange notes at a particular time and the price that you receive when you sell may not be favorable.

You may have difficulty selling any outstanding notes that you do not exchange.

If you do not exchange your outstanding notes for exchange notes in the exchange offer, you will continue to hold outstanding notes subject to restrictions on their transfer. Those transfer restrictions are described in the

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indenture governing the outstanding notes and in the legend contained on the outstanding notes, and arose because we originally issued the outstanding notes under an exemption from the registration requirements of the Securities Act.

In general, you may offer or sell your outstanding notes only if they are registered under the Securities Act and applicable state securities laws, or if they are offered and sold under an exemption from those requirements. We do not currently intend to register the outstanding notes under the Securities Act or any state securities laws. If a substantial amount of the outstanding notes is exchanged for a like amount of the exchange notes issued in the exchange offer, the liquidity of your outstanding notes could be adversely affected. See The Exchange Offer Consequences of Failure to Exchange Outstanding Notes for a discussion of additional consequences of failing to exchange your outstanding notes.

Risks Relating to the Notes

Our indebtedness could impair our financial condition and our ability to fulfill our debt obligations, including our obligations under the notes.

As of December 31, 2011, we had total indebtedness of $1.5 billion.

Our debt service obligations and restrictive covenants in our Credit Facility and the indenture governing the notes could have important consequences to you. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to the notes, which could in turn result in an event of default on the notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other purposes;
- diminish our ability to withstand a continued or future downturn in our business or the economy generally;
- require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

We are not prohibited under the indenture governing the notes from incurring additional indebtedness in addition to the notes. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above, and could adversely affect our ability to pay the interest on, and principal of, the notes.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make payments on the notes.

We have a holding company structure, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in these subsidiaries. As a result, our ability to make required payments on the notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, applicable state partnership and limited liability company laws and other laws and regulations. In addition, our subsidiaries are not prohibited by the terms of their respective organizational documents or the notes from incurring indebtedness, and the agreements governing such indebtedness may contain restrictions on the ability of our subsidiaries to make distributions to us. Moreover, if our subsidiaries

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were to incur significant amounts of indebtedness, such occurrence may inhibit their operating results, cash flow, financial condition and their ability to make distributions to us could suffer. An inability by our subsidiaries to make distributions to us would materially and adversely affect our ability to pay interest on, and the principal of, the notes because we expect distributions we receive from our subsidiaries to represent a significant portion of the cash that we use to pay interest on, and the principal of, the notes. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the notes, we may be required to adopt one or more alternatives, such as a refinancing of the notes. We cannot assure you that we would be able to refinance the notes.

The notes will be structurally subordinated to liabilities and indebtedness of our subsidiaries and effectively subordinated to any of our secured indebtedness to the extent of the assets securing such indebtedness.

We currently have no secured indebtedness outstanding, but the holders of any secured indebtedness that we may incur in the future would have claims with respect to our assets constituting collateral for such indebtedness that are effectively prior to your claims under the notes. In the event of a default on any such secured indebtedness or our bankruptcy, liquidation or reorganization, those assets would be available to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on the notes. Accordingly, any such secured indebtedness would effectively be senior to the notes to the extent of the value of the collateral securing the indebtedness. While the indenture governing the notes places some limitations on our ability to create liens, there are significant exceptions to these limitations that will allow us to secure some kinds of indebtedness without equally and ratably securing the notes. To the extent the value of the collateral is not sufficient to satisfy the secured indebtedness, the holders of that indebtedness would be entitled to share with the holders of the notes and the holders of other claims against us with respect to our other assets. Holders of the notes will participate ratably with all holders of our unsecured indebtedness that is deemed to be of the same class as the notes, and potentially with all of our other general creditors, based upon the respective amounts owed to each holder or creditor, in our remaining assets. In any of the foregoing events, we cannot assure you that there will be sufficient assets to pay amounts due on the notes. As a result, holders of notes may receive less than holders of secured indebtedness.

In addition, the notes are not guaranteed by our subsidiaries and our subsidiaries are generally not prohibited under the indenture from incurring additional indebtedness. As a result, holders of the notes will be structurally subordinated to claims of third-party creditors, including holders of indebtedness, of these subsidiaries. Claims of those other creditors, including trade creditors, secured creditors, governmental authorities and holders of indebtedness or guarantees issued by the subsidiaries, will generally have priority as to the assets of the subsidiaries over claims by the holders of the notes. As a result, rights of payment of holders of our indebtedness, including the holders of the notes, will be structurally subordinated to all those claims of creditors of our subsidiaries.

We may not be able to repurchase the notes upon a Change of Control Triggering Event.

Upon a change of control of us and a downgrade of the notes below an investment grade rating by Moody s Investors Service Inc. and Standard & Poor s Ratings Services, we will be required to make an offer to each holder of notes to repurchase all or any part of such holder s notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to the date of purchase. See Description of the Notes Change of Control. If such events were to occur, we cannot assure you that we will have the financial resources to purchase your notes, particularly if such events trigger a similar repurchase requirement for, or result in the acceleration of, other future indebtedness. In addition, our ability to repurchase the notes may be limited by law and regulations or the terms of other agreements relating to our indebtedness outstanding at the time. Any failure

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to purchase the notes as required under the indenture governing the notes would result in a default under the indenture, which could have material adverse consequences for us and the holders of the notes.

Our credit ratings may not reflect all risks of your investment in the notes.

The credit ratings assigned to the notes are not a recommendation to buy, sell or hold the notes and do not address all material risks relating to an investment in the notes, but rather reflect only the view of each rating agency at the time the rating is issued. We cannot assure you that these credit ratings will remain in effect for any given period of time or that a rating will not be lowered, suspended or withdrawn entirely by the applicable rating agencies. An increase in the level of our outstanding indebtedness, or other events that could have an adverse impact on our business, properties, financial condition, results of operations or prospects, may cause the rating agencies to downgrade our debt credit rating generally and the ratings on the notes. Each agency s rating should be evaluated independently of any other agency s rating. Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under further review for a downgrade, could affect the trading price for or liquidity of the notes, increase our corporate borrowing costs, limit our access to the capital markets or result in more restrictive covenants in future debt agreements.

The limited covenants applicable to the notes may not provide protection against some events or developments that may affect our ability to repay the notes or the trading prices for the notes.

The indenture governing the notes, among other things, does not:

- require us to maintain any financial ratios or specific levels of net worth, revenues, income, cash flow or liquidity and, accordingly, does not protect holders of the notes in the event that we experience significant adverse changes in our results of operations or financial condition;
- limit our ability to incur indebtedness that is equal in right of payment to the notes;
- limit our subsidiaries ability to incur indebtedness, which would rank senior to the notes;
- restrict our subsidiaries ability to issue securities or otherwise incur indebtedness that would be senior to our equity interests in our subsidiaries;
- restrict our ability to repurchase or prepay our securities; or
- restrict our ability to make investments or to repurchase or pay dividends or make other payments in respect of our common stock or other securities ranking junior to the notes.

As a result, you should consider the limited covenants in the indenture governing the notes as a significant factor in evaluating whether to invest in the notes.

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RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth information regarding our ratio of earnings to fixed charges for the periods shown. In calculating the ratio of earnings to fixed charges, earnings are calculated as (a) pre-tax income from continuing operations before equity earnings; plus (b) fixed charges; plus (c) distributed income of equity-method investees, excluding the proportionate share from 50% owned investees and unconsolidated majority-owned investees; and minus (d) interest capitalized. Fixed charges are calculated as the sum of (a) interest accrued, including the proportionate share from 50% owned investees and unconsolidated majority-owned investees; plus (b) an estimate of the interest within rental expense. Interest accrued does not include interest related to income taxes, including interest related to liabilities for uncertain tax positions, which is included in *provision (benefit) for income taxes* in our Consolidated Statement of Operations.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Ratio of earnings to fixed charges	(a)	(b)	3.08	16.70	3.98

(a) Earnings were inadequate to cover fixed charges by $433 million.

(b) Earnings were inadequate to cover fixed charges by $1,441 million.

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USE OF PROCEEDS

We will not receive any cash proceeds from the issuance of the exchange notes. In consideration for issuing the exchange notes, we will receive outstanding notes in like original principal amount at maturity. All outstanding notes received in the exchange offer will be cancelled. Because we are exchanging the exchange notes for the outstanding notes, which have substantially identical terms, the issuance of the exchange notes will not result in any increase in our indebtedness. The exchange offer is intended to satisfy our obligations under the registration rights agreement executed in connection with the sale of the outstanding notes.

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CAPITALIZATION

The following sets forth our cash and cash equivalents and capitalization at December 31, 2011. You should read this table in conjunction with Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements included elsewhere in this prospectus.

	December 31, 2011 (Millions)
Cash and cash equivalents	$ 526
Debt:	
Senior unsecured credit facility(1)	
Senior unsecured notes due 2017	400
Senior unsecured notes due 2022	1,100
Other	3
Total debt	1,503
Equity:	
Common stock (2 billion shares authorized at $0.01 par value; 197 million shares issued at December 31, 2011)	2
Additional paid-in capital	5,457
Noncontrolling interests	81
Accumulated other comprehensive income	219
Total equity	5,759
Total capitalization	$ 7,259

(1) Our Credit Facility, which was amended and became effective on November 1, 2011, provides for borrowings of up to $1.5 billion. Our future borrowing capacity will be reduced by letters of credit issued under the Credit Facility. See Description of Other Indebtedness.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following tables set forth our selected historical consolidated financial data for the periods indicated below. Our selected historical consolidated financial data as of December 31, 2011 and 2010 and for the fiscal years ended December 31, 2011, 2010 and 2009 have been derived from our audited historical consolidated financial statements included elsewhere in this prospectus. Our selected historical consolidated financial data as of December 31, 2009, 2008 and 2007 and for the years ended December 31, 2008 and 2007 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, and our consolidated financial statements and related notes included elsewhere in this prospectus.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(Millions, except per share amounts)				
Statement of operations data:					
Revenues	$ 3,988	$ 4,034	$ 3,681	$ 6,184	$ 4,479
Income (loss) from continuing operations(1)	(272)	(1,275)	147	815	191
Income (loss) from discontinued operations(2)	(20)	(8)	(7)	(87)	146
Net income (loss)	(292)	(1,283)	140	728	337
Less: Net income attributable to noncontrolling interests	10	8	6	8	11
Net income (loss) attributable to WPX Energy	$ (302)	$ (1,291)	$ 134	$ 720	$ 326
Basic and diluted earnings (loss) per common share:					
Income (loss) from continuing operations	$ (1.43)	$ (6.51)	$ 0.71	$ 4.09	$ 0.92
Income (loss) from discontinued operations	$ (0.10)	$ (0.04)	$ (0.03)	$ (0.44)	$ 0.74

	As of December 31,				
	2011	2010	2009	2008	2007
	(Millions)				
Balance sheet data					
Notes payable to Williams current(3)	$	$ 2,261	$ 1,216	$ 925	$ 656
Third party debt	1,503				
Total assets	10,432	9,846	10,553	11,624	10,571
Total equity(3)	5,759	4,484	5,390	5,493	4,345

(1) Loss from continuing operations for the year ended December 31, 2011 includes $547 million of impairment charges related to producing properties in the Barnett Shale and Powder River basins and costs of acquired unproved reserves in the Powder River basin. Loss from continuing operations 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 Note 7 of Notes to Consolidated Financial Statements for further discussion of asset sales, impairments and other accruals in 2011, 2010 and 2009.

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(2) Income (loss) from discontinued operations includes our Arkoma operations which are classified as held for sale as of December 31, 2011 and Williams former power business that was substantially disposed of in 2007. The activity in 2011, 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 total equity as of December 31, 2011.

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THE EXCHANGE OFFER

Purpose of the Exchange Offer

This exchange offer is being made pursuant to the registration rights agreement that we entered into with the initial purchasers of the outstanding notes on November 14, 2011. The summary of the registration rights agreement contained herein does not purport to be complete and is qualified in its entirety by reference to the registration rights agreement. A copy of the registration rights agreement is filed as an exhibit to the registration statement of which this prospectus forms a part. Each broker-dealer that receives exchange notes for its own account in exchange for outstanding notes, where such exchange notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such exchange notes. See Plan of Distribution.

Terms of the Exchange Offer; Expiration Time

This prospectus and the accompanying letter of transmittal together constitute the exchange offer. Subject to the terms and conditions in this prospectus and the letter of transmittal, we will accept for exchange outstanding notes that are validly tendered at or before the expiration time and are not validly withdrawn as permitted below. The expiration time for the exchange offer is 5:00 p.m., New York City time, on , 2012, or such later date and time to which we, in our sole discretion, extend the exchange offer.

Upon expiration of the exchange offer, subject to the conditions described below under Conditions to the Exchange Offer, all outstanding 5.250% Senior Notes due 2017 that are validly tendered and not withdrawn will be exchanged for an equal principal amount of the 2017 notes, and all outstanding 6.000% Senior Notes due 2022 that are validly tendered and not withdrawn will be exchanged for an equal principal amount of the 2022 notes.

We expressly reserve the right, in our sole discretion:

- to extend the expiration time;
- if any of the conditions set forth below under Conditions to the Exchange Offer has not been satisfied, to terminate the exchange offer and not accept any outstanding notes for exchange; and
- to amend the exchange offer in any manner.

We will give notice of any extension, delay, non-acceptance, termination or amendment as promptly as practicable by a public announcement, and in the case of an extension, no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled expiration time. In the event of a material change in the exchange offer, including the waiver of a material condition, we will extend the offer period if necessary so that at least five business days remain in the exchange offer following notice of the material change.

During an extension, all outstanding notes previously tendered will remain subject to the exchange offer and may be accepted for exchange by us, upon expiration of the exchange offer, unless validly withdrawn.

Each broker-dealer that receives exchange notes for its own account in exchange for outstanding notes, where such outstanding notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such exchange notes. See Plan of Distribution.

How to Tender Outstanding Notes for Exchange

Only a record holder of outstanding notes may tender in the exchange offer. When the holder of outstanding notes tenders and we accept outstanding notes for exchange, a binding agreement between us and the tendering

holder is created, subject to the terms and conditions in this prospectus and the accompanying letter of transmittal. Except as set forth below, a holder of outstanding notes who desires to tender outstanding notes for exchange must, at or prior to the expiration time

- cause an agent s message to be transmitted by DTC to the exchange agent at the address set forth below under the heading The Exchange Agent, and the exchange agent must receive, at or prior to the expiration time, a confirmation of the book-entry transfer of the outstanding notes being tendered into the exchange agent s account at DTC, along with the agent s message; or

- if time will not permit the procedures for book-entry transfer to be completed by the expiration time, the holder may effect a tender by complying with the guaranteed delivery procedures described below.

The term agent s message means a message that:

- is transmitted by DTC;

- is received by the exchange agent and forms a part of a book-entry transfer;

- states that DTC has received an express acknowledgement that the tendering holder has received and agrees to be bound by, and makes each of the representations and warranties contained in, the letter of transmittal; and

- states that we may enforce the letter of transmittal against such holder.

By transmitting an agent s message, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by the terms of the letter of transmittal just as if you had signed it.

The method of delivery of the outstanding notes, the agent s message and all other required documents to the exchange agent is at the election and sole risk of the holder. In all cases, you should allow sufficient time to assure timely delivery. No letters of transmittal or outstanding notes should be sent directly to us.

We will determine in our sole discretion all questions as to the validity, form and eligibility (including time of receipt) of outstanding notes tendered for exchange and all other required documents. We reserve the absolute right to:

- reject any and all tenders of any outstanding note not validly tendered;

- refuse to accept any outstanding note if, in our judgment or the judgment of our counsel, acceptance of the outstanding note may be deemed unlawful;

- waive any defects or irregularities or conditions of the exchange offer; and

- determine the eligibility of any holder who seeks to tender outstanding notes in the exchange offer.

Our determinations under, and of the terms and conditions of, the exchange offer, including the letter of transmittal and the instructions to it, or as to any questions with respect to the tender of any outstanding notes, will be final and binding on all parties. To the extent we waive any conditions to the exchange offer, we will waive such conditions as to all outstanding notes. Holders must cure any defects and irregularities in connection with tenders of outstanding notes for exchange within such reasonable period of time as we will determine, unless we waive such defects or irregularities. Neither we, the exchange agent nor any other person will be under any duty to give notification of any defect or irregularity with respect to any tender of outstanding notes for exchange, nor will any of us incur any liability for failure to give such notification.

If you beneficially own outstanding notes registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your outstanding notes in the exchange offer, you should contact the registered holder promptly and instruct it to tender on your behalf.

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Each broker-dealer that receives exchange notes for its own account in exchange for outstanding notes, where such exchange notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such exchange notes. See Plan of Distribution.

WE MAKE NO RECOMMENDATION TO THE HOLDERS OF THE OUTSTANDING NOTES AS TO WHETHER TO TENDER OR REFRAIN FROM TENDERING ALL OR ANY PORTION OF THEIR OUTSTANDING NOTES IN THE EXCHANGE OFFER. IN ADDITION, WE HAVE NOT AUTHORIZED ANYONE TO MAKE ANY SUCH RECOMMENDATION. HOLDERS OF THE OUTSTANDING NOTES MUST MAKE THEIR OWN DECISION AS TO WHETHER TO TENDER PURSUANT TO THE EXCHANGE OFFER AND, IF SO, THE AGGREGATE AMOUNT OF OUTSTANDING NOTES TO TENDER, AFTER READING THIS PROSPECTUS AND THE LETTER OF TRANSMITTAL AND CONSULTING WITH THEIR ADVISERS, IF ANY, BASED ON THEIR FINANCIAL POSITIONS AND REQUIREMENTS.

Book-Entry Transfers

Any financial institution that is a participant in DTC s system must make book-entry delivery of outstanding notes by causing DTC to transfer the outstanding notes into the exchange agent s account at DTC in accordance with DTC s Automated Tender Offer Program, known as ATOP. Such participant should transmit its acceptance to DTC at or prior to the expiration time or comply with the guaranteed delivery procedures described below. DTC will verify such acceptance, execute a book-entry transfer of the tendered outstanding notes into the exchange agent s account at DTC and then send to the exchange agent confirmation of such book-entry transfer. The confirmation of such book-entry transfer will include an agent s message. An agent s message must be transmitted to and received by the exchange agent at the address set forth below under The Exchange Agent at or prior to the expiration time of the exchange offer, or the holder must comply with the guaranteed delivery procedures described below.

Guaranteed Delivery Procedures

If a holder of outstanding notes desires to tender such outstanding notes and the procedure for book-entry transfer cannot be completed on a timely basis, a tender may be effected if:

- at or prior to the expiration time, the exchange agent receives from an eligible institution a validly completed and executed notice of guaranteed delivery, substantially in the form accompanying this prospectus, by facsimile transmission, mail or hand delivery, setting forth the name and address of the holder of the outstanding notes being tendered and the amount of the outstanding notes being tendered. The notice of guaranteed delivery will state that the tender is being made and guarantee that within three New York Stock Exchange trading days after the date of execution of the notice of guaranteed delivery, a book-entry confirmation together with an agent s message, will be transmitted to the exchange agent; and

- the exchange agent receives a book-entry confirmation, together with an agent s message, within three New York Stock Exchange trading days after the date of execution of the notice of guaranteed delivery.

The term eligible institution means an institution that is a member in good standing of a Medallion Signature Guarantee Program recognized by the exchange agent, for example, the Securities Transfer Agents Medallion Program, the Stock Exchanges Medallion Program or the New York Stock Exchange Medallion Signature Program. An eligible institution includes firms that are members of a registered national securities exchange, members of the National Association of Securities Dealers, Inc., commercial banks or trust companies having an office in the United States or certain other eligible guarantors.

The notice of guaranteed delivery must be received prior to the expiration time.

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Withdrawal Rights

You may withdraw tenders of your outstanding notes at any time prior to the expiration time.

For a withdrawal to be effective, a written notice of withdrawal, by facsimile or by mail, must be received by the exchange agent, at the address set forth below under The Exchange Agent, prior to the expiration time. Any such notice of withdrawal must:

- specify the name of the person having tendered the outstanding notes to be withdrawn;
- identify the outstanding notes to be withdrawn, including the principal amount of such outstanding notes; and
- specify the name and number of the account at DTC to be credited with the withdrawn outstanding notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form and eligibility (including time of receipt) of such notices and our determination will be final and binding on all parties. Any tendered outstanding notes validly withdrawn will be deemed not to have been validly tendered for exchange for purposes of the exchange offer. Properly withdrawn notes may be re-tendered by following one of the procedures described above under How to Tender Outstanding Notes for Exchange at any time at or prior to the expiration time.

Acceptance of Outstanding Notes for Exchange; Delivery of Exchange Notes

All of the conditions to the exchange offer must be satisfied or waived at or prior to the expiration of the exchange offer. Promptly following the expiration time we will accept for exchange all outstanding notes validly tendered and not validly withdrawn as of such date. We will promptly thereafter issue exchange notes for all validly tendered outstanding notes. For purposes of the exchange offer, we will be deemed to have accepted validly tendered outstanding notes for exchange when, as and if we have given oral or written notice to the exchange agent, with written confirmation of any oral notice to be given promptly thereafter. See below under Conditions to the Exchange Offer for a discussion of the conditions that must be satisfied before we accept any outstanding notes for exchange.

For each outstanding note accepted for exchange, the holder will receive an exchange note registered under the Securities Act having a principal amount equal to, and in the denomination of, that of the surrendered outstanding note. Holders whose outstanding notes are exchanged for exchange notes will not receive a payment in respect of interest accrued but unpaid on such outstanding notes from the date of original issuance of the outstanding notes or the most recent interest payment date up to but excluding the settlement date. Instead, interest on the exchange notes received in exchange for such outstanding notes will (i) accrue from the last date on which interest was paid on such outstanding notes or, if no interest has been paid on such outstanding notes, from the original issue date of such outstanding notes and (ii) accrue at the same rate as and be payable on the same dates as interest was payable on such outstanding notes. Accordingly, registered holders of exchange notes that are outstanding on the relevant record date for the first interest payment date following the consummation of the exchange offer will receive interest accruing from the most recent date through which interest has been paid on the outstanding notes or, if no interest has been paid on such outstanding notes, from the original issue date of such outstanding notes. However, if any interest payment occurs prior to the settlement date on any outstanding notes already tendered for exchange in the exchange offer, the holder of such outstanding notes will be entitled to receive such interest payment. Outstanding notes that we accept for exchange will cease to accrue interest from and after the date of consummation of the exchange offer.

If we do not accept any tendered outstanding notes, or if a holder submits outstanding notes for a greater principal amount than the holder desires to exchange, we will return such unaccepted or non-exchanged outstanding notes without cost to the tendering holder. Such non-exchanged outstanding notes will be credited to an account maintained with DTC. We will have such non-exchanged outstanding notes credited to DTC promptly after the withdrawal, rejection of tender or termination of the exchange offer, as applicable.

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Conditions to the Exchange Offer

The exchange offer is not conditioned upon the tender of any minimum principal amount of outstanding notes. Notwithstanding any other provision of the exchange offer, or any extension of the exchange offer, we will not be required to accept for exchange, or to issue exchange notes in exchange for, any outstanding notes and may terminate or amend the exchange offer, by oral (promptly confirmed in writing) or written notice to the exchange agent or by a timely press release, if at any time before the expiration of the exchange offer, any of the following conditions exist:

- any action or proceeding is instituted or threatened in any court or by or before any governmental agency challenging the exchange offer or that we believe might be expected to prohibit or materially impair our ability to proceed with the exchange offer;

- any stop order is threatened or in effect with respect to either (1) the registration statement of which this prospectus forms a part or (2) the qualification of the indenture governing the notes under the Trust Indenture Act of 1939, as amended;

- any law, rule or regulation is enacted, adopted, proposed or interpreted that we believe might be expected to prohibit or impair our ability to proceed with the exchange offer or to materially impair the ability of holders generally to receive freely tradable exchange notes in the exchange offer. See Consequences of Failure to Exchange Outstanding Notes, below;

- any change or a development involving a prospective change in our business, properties, assets, liabilities, financial condition, operations or results of operations taken as a whole, that is or may be adverse to us;

- any declaration of war, armed hostilities or other similar international calamity directly or indirectly involving the United States, or the worsening of any such condition that existed at the time that we commence the exchange offer; or

- we become aware of facts that, in our reasonable judgment, have or may have adverse significance with respect to the value of the outstanding notes or the exchange notes to be issued in the exchange offer.

Accounting Treatment

For accounting purposes, we will not recognize gain or loss upon the issuance of the exchange notes for outstanding notes.

Fees and Expenses

We will not make any payment to brokers, dealers, or others soliciting acceptance of the exchange offer except for reimbursement of mailing expenses. We will pay the cash expenses to be incurred in connection with the exchange offer, including:

- SEC registration fees;

- fees and expenses of the exchange agent and trustee;

- our accounting and legal fees;

- printing fees; and
- related fees and expenses.

Transfer Taxes

Holders who tender their outstanding notes for exchange will not be obligated to pay any transfer taxes in connection with the exchange. If, however, exchange notes issued in the exchange offer are to be delivered to, or

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are to be issued in the name of, any person other than the holder of the outstanding notes tendered, or if a transfer tax is imposed for any reason other than the exchange of outstanding notes in connection with the exchange offer, then the holder must pay these transfer taxes, whether imposed on the registered holder or on any other person. If satisfactory evidence of payment of or exemption from these taxes is not submitted with the letter of transmittal, the amount of these transfer taxes will be billed directly to the tendering holder.

The Exchange Agent

We have appointed The Bank of New York Mellon Trust Company, N.A. as our exchange agent for the exchange offer. Questions and requests for assistance respecting the procedures for tendering or withdrawing tenders of outstanding notes, requests for additional copies of this prospectus or of the letter of transmittal and requests for notices of guaranteed delivery should be directed to the exchange agent at its address below:

The Bank of New York Mellon Trust Company, N.A.

c/o The Bank of New York Mellon Corporation

Corporate Trust Operations Reorganization Unit

101 Barclay Street, Floor 7 East

New York, N.Y. 10286

Attn: Diane Amoroso

Telephone: 212-815-2742

Fax: 212-298-1915

Consequences of Failure to Exchange Outstanding Notes

Outstanding notes that are not tendered or are tendered but not accepted will, following the consummation of the exchange offer, continue to be subject to the provisions in the indenture and the legend contained on the outstanding notes regarding the transfer restrictions of the outstanding notes. In general, outstanding notes, unless registered under the Securities Act, may not be offered or sold except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not currently anticipate that we will take any action to register under the Securities Act or under any state securities laws the outstanding notes that are not tendered in the exchange offer or that are tendered in the exchange offer but are not accepted for exchange.

Holders of the exchange notes and any outstanding notes that remain outstanding after consummation of the exchange offer will vote together as a single series for purposes of determining whether holders of the requisite percentage of the series have taken certain actions or exercised certain rights under the indenture governing the notes.

Consequences of Exchanging Outstanding Notes

We have not requested, and do not intend to request, an interpretation by the Commission staff as to whether the exchange notes issued in the exchange offer may be offered for sale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. However, based on interpretations of the Commission staff, as set forth in a series of no-action letters issued to third parties, we believe that the exchange notes may be offered for resale, resold or otherwise transferred by holders of those exchange notes without compliance with the registration and prospectus delivery provisions of the Securities Act, provided that:

- the holder is not an affiliate of ours within the meaning of Rule 405 promulgated under the Securities Act;

the exchange notes issued in the exchange offer are acquired in the ordinary course of the holder s business;

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- neither the holder, nor, to the actual knowledge of such holder, any other person receiving exchange notes from such holder, has any arrangement or understanding with any person to participate in the distribution of the exchange notes issued in the exchange offer;

- if the holder is not a broker-dealer, the holder is not engaged in, and does not intend to engage in, a distribution of the exchange notes;

- if such a holder is a broker-dealer, such broker-dealer will receive the exchange notes for its own account in exchange for outstanding notes;

- such outstanding notes were acquired by such broker-dealer as a result of market-making or other trading activities; and

- it will deliver a prospectus meeting the requirements of the Securities Act in connection with the resale of exchange notes issued in the exchange offer, and will comply with the applicable provisions of the Securities Act with respect to resale of any exchange notes. (In no-action letters issued to third parties, the Commission has taken the position that broker-dealers may fulfill their prospectus delivery requirements with respect to exchange notes (other than a resale of an unsold allotment from the original sale of outstanding notes) by delivery of the prospectus relating to the exchange offer). See Plan of Distribution for a discussion of the exchange and resale obligations of broker-dealers in connection with the exchange offer.

Each holder participating in the exchange offer will be required to furnish us with a written representation in the letter of transmittal that they meet each of these conditions and agree to these terms.

However, because the Commission has not considered the exchange offer for our outstanding notes in the context of a no-action letter, we cannot guarantee that the Commission staff would make similar determinations with respect to this exchange offer. If our belief is not accurate and you transfer an exchange note without delivering a prospectus meeting the requirements of the federal securities laws or without an exemption from these laws, you may incur liability under the federal securities laws. We do not and will not assume, or indemnify you against, this liability.

Any holder that is an affiliate of ours or that tenders outstanding notes in the exchange offer for the purpose of participating in a distribution:

- may not rely on the applicable interpretation of the SEC staff s position contained in Exxon Capital Holdings Corp., SEC No-Action Letter (April 13, 1988), Morgan, Stanley & Co., Inc., SEC No-Action Letter (June 5, 1991) and Shearman & Sterling, SEC No-Action Letter (July 2, 1993); and

- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction.

The exchange notes issued in the exchange offer may not be offered or sold in any state unless they have been registered or qualified for sale in such state or an exemption from registration or qualification is available and complied with by the holders selling the exchange notes. We currently do not intend to register or qualify the sale of the exchange notes in any state where we would not otherwise be required to qualify.

Filing of Shelf Registration Statements

Pursuant to the registration rights agreement that we entered into with the initial purchasers of the outstanding notes on November 14, 2011, we agreed, among other things, that if:

(1) we are not permitted to consummate the exchange offer because the exchange offer is not permitted by applicable law or Commission policy; or

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(2) any holder of Transfer Restricted Securities (as defined in the registration rights agreement) notifies us prior to the 20th day following consummation of the exchange offer that (a) it is prohibited by law or Commission policy from participating in the exchange offer; (b) it may not resell the exchange notes acquired by it in the exchange offer to the public without delivering a prospectus, and the prospectus contained in the Exchange Offer Registration Statement (as defined in the registration rights agreement) is not appropriate or available for such resales; or (c) it is a broker-dealer and owns notes acquired directly from us or an affiliate of ours;

then we will use our commercially reasonable efforts to file with the Commission within 60 days after such filing obligation arises (or, if later, the date by which we are obligated to file an Exchange Offer Registration Statement) a shelf registration statement (the Shelf Registration Statement) providing for the resale by the holders of the Transfer Restricted Securities of all of their Transfer Restricted Securities; provided, however, that no holder of Transfer Restricted Securities is entitled to have its Transfer Restricted Securities included in a Shelf Registration Statement if such holder has not satisfied certain conditions relating to the provision of information in connection with the Shelf Registration Statement.

We will use our commercially reasonable efforts to cause any Shelf Registration Statement to be declared effective by the Commission or to become automatically effective in accordance with the rules and regulations of the Commission on or prior to 180 days after any such filing obligation arises (or, if later, the date by which we are obligated to use our commercially reasonable efforts to have the Exchange Offer Registration Statement declared effective).

Although we intend, if required, to file the Shelf Registration Statement, we cannot assure you that the Shelf Registration Statement will be filed or, if filed, that it will become or remain effective.

The foregoing description is a summary of certain provisions of the registration rights agreement. It does not restate the registration rights agreement in its entirety. We urge you to read the registration rights agreement, which is an exhibit to the registration statement of which this prospectus forms a part and can also be obtained from us. See Where You Can Find More Information.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

General

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 exploiting our significant natural gas reserves 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 an approximate 69 percent controlling ownership interest in Apco Oil and Gas International Inc. (Apco), which holds oil and gas concessions in South America and trades on the NASDAQ Capital Market under the symbol APAGF.

In conjunction with 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, NGL and oil production, along with 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. We do not expect to continue to provide these services to Williams Partners 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 price risk management activities. 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 product 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.

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes included 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.

Separation from Williams

On February 16, 2011, Williams announced that its board of directors had approved pursuing a plan to separate Williams businesses into two stand-alone, publicly-traded companies. As a result, WPX Energy, Inc. was 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 then wholly-owned subsidiaries WPX Energy Holdings, LLC (formerly Williams Production Holdings, LLC) and WPX Energy Production, LLC (formerly Williams Production Company, LLC), as well as all ongoing operations of WPX Energy Marketing, LLC (formerly Williams Gas Marketing, Inc.). Additionally, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its approximate 69 percent ownership interest in Apco in October 2011. We refer to the collective contributions described herein as the Contribution.

On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011, of WPX common stock to Williams stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date.

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Basis of Presentation

The consolidated financial statements included elsewhere in this prospectus, principally represented the Exploration & Production segment entity of Williams that were contributed in July 2011 and October 2011.

Up to the spin-off, our historical results included allocations of costs for corporate functions historically provided to us by Williams. See Note 4 of our Notes to Consolidated Financial Statements for more information.

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 as we operate as an independent, publicly-traded company. We have entered into a transition services agreement with Williams that provides for continuation for some of these services in exchange for fees specified in these agreements.

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 totaling $29 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. 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.

Overview

The following table presents our production volumes and financial highlights for 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
Production Sales Data:(1)			
Domestic natural gas (MMcf)	413,520	392,776	417,537
Domestic NGLs (MBbls)	10,058	8,056	4,721
Domestic oil (MBbls)	2,676	857	803
Domestic combined equivalent volumes (MMcfe)(2)	489,926	446,252	450,679
Domestic per day combined equivalent volumes (MMcfe/d)	1,342	1,223	1,235
Domestic combined equivalent volumes (MBoe)	81,654	74,375	75,113
International combined equivalent volumes (MMcfe)(2)(3)	20,810	19,940	19,675
Financial Data (millions):			
Total domestic revenues	$ 3,878	$ 3,945	$ 3,603
Total international revenues	$ 110	$ 89	$ 78
Consolidated operating income (loss)	$ (335)	$ (1,337)	$ 317
Consolidated capital expenditures	$ 1,572	$ 1,856	$ 1,434

(1) Excludes production from our Arkoma Basin operations which are classified as discontinued operations and comprise less than one percent of our total production.
(2) Oil and NGLs were converted to MMcfe using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.
(3) Includes approximately 69 percent of Apco s production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

Our 2011 results were impacted by low natural gas prices and due primarily to decreases in forward natural gas prices we have recognized in 2011 pre-tax impairment charges of $547 million associated with impairments of certain producing properties. Additionally, our 2010 operating results were negatively impacted 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. See Note 7 of Notes to the Consolidated Financial Statements for more information.

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 were inconclusive and raised 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 third quarter 2011. Further, we assessed the impact of

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this well on our ability to recover the remaining lease acquisition costs associated with the acreage in Columbia County. During 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 connection with the separation from Williams, we entered into a $1.5 billion revolving credit agreement in June 2011. In November we issued $1.5 billion of senior notes consisting of $1.1 billion at 6.0% due 2022 and $400 million at 5.25% due 2017. Approximately $981 million of these proceeds were distributed to Williams. At December 31, 2011, we had $488 million of cash available for domestic operations and $38 million available for international operations.

Outlook

Although we are experiencing low natural gas prices, we believe we are well positioned to execute our business strategy of finding and developing reserves and producing natural gas, natural gas liquids and oil at costs that will generate an attractive rate of return on our consolidated incremental development investments. Our focus for 2012 is to continue to develop our natural gas portfolio to maintain current natural gas production levels, including the associated leasehold acreage, and grow our oil and natural gas liquids production. At current commodity pricing levels, we are focused on continuing to develop a more balanced reserve and production portfolio that will include a larger portion oil and NGLs reserves than we have historically maintained. With lower natural gas prices, we will continue to maintain our focus on drilling strategically to manage leasehold expirations and maintain our liquidity. A continued decrease in forward natural gas prices could signal a need to reduce capital spending in 2012 to maintain the liquidity and balance sheet we believe necessary to run our business.

We believe that our portfolio of reserves provides us an opportunity to continue to grow in our areas where we have oil production (Williston basin) and high concentrations of natural gas liquids (Piceance basin), which we believe will generate long-term sustainable value for shareholders. If gas prices were to increase, we believe we have the operational flexibility to respond by increasing our drilling in our natural gas areas. We expect 2012 capital expenditures to be approximately $1.2 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 (primarily Piceance) with high concentrations of NGLs; and
- Continuing to maintain an active economic 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;

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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.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we will begin entering into commodity derivative contracts that will continue to serve as economic hedges but will not be designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur. We believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2011 that are included in accumulated other comprehensive income have been and will continue to be transferred to earnings during the same periods in which the forecasted hedged transactions are recognized.

On April 2, 2012, we announced that we had entered into an agreement to sell certain assets for $306 million in the Barnett Shale located in north central Texas, as well as our interests in the Arkoma Basin in southeastern Oklahoma. These assets include interests in undeveloped acreage, producing wells, and pipelines. The properties represent less than five percent of our year-end 2011 proved domestic reserves and approximately five percent of total production. The transaction is subject to certain closing adjustments that will impact the total proceeds to be received.

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 2012 we have the following contracts as of December 31, 2011 for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		2012 Natural Gas		
		Volume (BBtu/d)		Weighted Average Price ($/MMBtu)
Location swaps	Rockies	135	$	4.76
Location swaps	San Juan	110	$	4.94
Location swaps	Mid-Continent	88	$	4.76
Location swaps	Southern California	33	$	5.14
Location swaps	Northeast	143	$	5.58
Total all swaps		508	$	5.06

	2012 Crude Oil			
	Volume (Bbls/d)	Weighted Average Price ($/Bbl) Floor-Ceiling for Collars		
WTI crude oil fixed-price	7,169	$97.32		
WTI crude oil costless collar	2,000	$	85.00	$106.30

We entered into natural gas liquid swaps during January 2012 consisting of 3,661 barrels per day at a weighted average price of $50.74 per whole barrel.

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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 years ended December 31, 2011, 2010 and 2009:

		2011				2010				2009			
		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	45	$	5.30	$7.10	100	$	6.53	$8.94	150	$	6.11	$9.04
Collar agreements	San Juan	90	$	5.27	$7.06	233	$	5.75	$7.82	245	$	6.58	$9.62
Collar agreements	Mid-Continent	80	$	5.10	$7.00	105	$	5.37	$7.41	95	$	7.08	$9.73
Collar agreements	Southern California	30	$	5.83	$7.56	45	$	4.80	$6.43				
Collar agreements	Other	30	$	6.50	$8.14	28	$	5.63	$6.87				
NYMEX and basis fixed-price swaps		372	$5.22			120	$4.40			106	$3.67		

	2011 Crude Oil Volume (Bbls/d)	Weighted Average Price ($/Bbl)	
WTI crude oil fixed-price	3,315	$	95.88

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.

Results of Operations

Operations of our company are located in the United States and South America and are organized into Domestic and International reportable segments.

Domestic 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. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related hedges coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco, an oil and gas exploration and production company with concessions primarily in Argentina.

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2011 vs. 2010

Revenue Analysis

	Years ended December 31, 2011	2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$ 1,779	$ 1,797	$ (18)	(1)%
Natural gas liquid sales	404	282	122	43%
Oil and condensate sales	229	57	172	NM
Total product revenues including sales to Williams	2,412	2,136	276	13%
Gas management, including sales to Williams	1,428	1,742	(314)	(18)%
Hedge ineffectiveness and mark to market gains and losses	29	27	2	7%
Other	9	40	(31)	(78)%
Total domestic revenues	$ 3,878	$ 3,945	$ (67)	(2)%
Total international revenues	$ 110	$ 89	$ 21	24%
Total revenues	$ 3,988	$ 4,034	$ (46)	(1)%

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

Domestic Revenues

Significant variances in comparative revenues reflect:

- $18 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $4.30 compared to $4.57 in 2010 on production sales volumes of 413,520 MMcf and 392,776 MMcf, respectively. Without hedges, our natural gas price per Mcf in 2011 was $3.51 compared to $3.73 in 2010.

- $122 million increase in natural gas liquids sales reflects a per barrel price of $40.17 in 2011 compared to $35.02 in 2010. Production sales volumes were 10,058 Mbbls in 2011 versus 8,056 Mbbls in 2010;

- $172 million increase in oil and condensate sales reflects a per barrel price of $85.38 (including the impact of hedges) in 2011 compared to $66.32 in 2010. Production sales volumes in 2011 were 2,676 Mbbls compared to 857 Mbbls in 2010. Production in 2011 reflected a full year of production associated with producing wells acquired in the Bakken acquisition completed in late 2010 as well as production from wells drilled during 2011.

- A $314 million decrease in gas management revenues primarily due to a 7 percent decrease in average prices on physical natural gas sales and 12 percent lower natural gas sales volumes. We experienced a similar decrease of $298 million in related gas management costs and expenses; and

A $31 million decrease in other revenues primarily related to the absence of gathering revenues associated with the gathering and processing assets in Colorado s Piceance Basin that were sold to Williams Partners in the fourth quarter of 2010.

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International Revenues

International revenues increased primarily due to increased average oil sales prices.

Cost and operating expense and operating income (loss) analysis:

	Year ended December 31, 2011	2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating, including expenses with Williams	$ 268	$ 267	$ 1	%
Gathering, processing and transportation, including expenses with Williams	499	326	173	53%
Taxes other than income	119	109	10	9%
Gas management, including charges for unutilized pipeline capacity	1,473	1,771	(298)	(17)%
Exploration	131	67	64	96%
Depreciation, depletion and amortization	927	858	69	8%
Impairment of producing properties and costs of acquired unproved reserves	547	678	(131)	(19)%
Goodwill impairment		1,003	(1,003)	NM
General and administrative	273	244	29	12%
Other net	(2)	(19)	17	(89)%
Total domestic costs and expenses	$ 4,235	$ 5,304	$ (1,069)	(20)%
International costs and expenses:				
Lease and facility operating	$ 27	$ 19	$ 8	42%
Taxes other than income	21	16	5	31%
Exploration	3	6	(3)	(50)%
Depreciation, depletion and amortization	22	17	5	29%
General and administrative	12	9	3	33%
Other net	3		3	NM
Total international costs and expenses	$ 88	$ 67	$ 21	31%
Total costs and expenses	$ 4,323	$ 5,371	$ (1,048)	(20)%
Domestic operating income (loss)	$ (357)	$ (1,359)	$ 1,002	(74)%
International operating income	$ 22	$ 22	$	%

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

Domestic Costs

Significant variances in comparative costs and expenses reflect:

Lease and facility operating expense reflects higher costs associated with higher production and 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. Lease and facility operating expense in 2011 averaged $0.55 per Mcfe compared to $0.60 per Mcfe during 2010.

$173 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

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and an increase in natural gas liquids volumes processed at Williams Partners Willow Creek plant. During 2011, gathering, processing and transportation expenses were $132 million higher due to fees paid to Williams Partners pursuant to the gathering and processing agreement associated with the assets sold Williams Partners in the fourth quarter of 2010. During 2010, our operating costs were $58 million 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. Our gathering, processing and transportation charges averaged $1.02 per Mcfe in 2011 compared to an average of $0.73 per Mcfe in 2010.

$10 million higher taxes other than income primarily associated with the increase in oil and natural gas liquid sales volumes.

$298 million decrease in gas management expenses, primarily due to a 6 percent decrease in average prices on physical natural gas cost of sales and a 12 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 $37 million and $48 million in 2011 and 2010, respectively, for unutilized pipeline capacity. Gas management expenses in 2011 and 2010 also include $10 million and $2 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage.

$64 million increase in exploration expense 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 leasehold acquisitions. Partially off-setting these increases is the absence of $15 million in dry hole charges recognized in 2010 associated with the Paradox basin.

$69 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 Partners in 2010. During 2011 our depreciation, depletion and amortization averaged $1.89 per Mcfe compared to an average $1.92 per Mcfe in 2010.

$547 million of property impairments in 2011 compared to $678 million in 2010.

The absence of the goodwill impairment from 2010 to 2011 as previously discussed.

$29 million higher general and administrative expenses primarily due to higher wages, salary and benefits costs primarily as a result of an increase in the number of employees. Our general and administrative expenses in 2011 averaged $0.56 per Mcfe in 2011 compared to an average of $0.55 per Mcfe in 2010. Additionally, general and administrative expenses in 2011 reflect approximately $5 million in costs associated with our initial public offering efforts and approximately $5 million in stock based compensation expense.

Other-net in 2010 reflects a gain on sale of $12 million associated with a third-party sale of a portion of gathering and processing assets in the Piceance basin and a $7 million gain on exchange of undeveloped leasehold acreage with a third party.

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International costs

International costs increased primarily due to increased production and lifting costs due to greater operating and maintenance activity and increased operating taxes associated with increased revenues.

Consolidated results below operating income (loss)

	Years ended December 31, 2011	Years ended December 31, 2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Consolidated operating loss	$ (335)	$ (1,337)	$ 1,002	(75)%
Interest expense:				
Interest expense Williams	(96)	(119)	23	(19)%
Interest expense other	(21)	(5)	(16)	NM
Total interest expense, including expenses with Williams	(117)	(124)	7	(6)%
Interest capitalized	9	16	(7)	(44)%
Investment income and other	26	21	5	24%
Loss from continuing operations before income taxes	(417)	(1,424)	1,007	(71)%
Benefit for income taxes	(145)	(149)	4	(3)%
Loss from continuing operations	(272)	(1,275)	1,003	(79)%
Loss from discontinued operations	(20)	(8)	(12)	150%
Net loss	(292)	(1,283)	991	(77)%
Less: Net income attributable to noncontrolling interests	10	8	2	25%
Net loss attributable to WPX Energy	$ (302)	$ (1,291)	$ 989	(77)%

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

Interest expense Williams in 2011 only reflects interest for six months as Williams cancelled and contributed to capital all amounts due under our unsecured notes payable with them on June 30, 2011. All cash receipts and cash expenditures transferred to or from Williams from July 1, 2011 to November 30, 2011 were considered owner s equity transactions between us and Williams and therefore no interest expense was recorded during this period. The interest expense-other in 2011 primarily reflects interest expense on our senior notes issued in November 2011.

Our investment income results primarily from equity earnings associated with our international and domestic equity investments.

Benefit for income taxes changed due to the lower pre-tax loss in 2011 compared to the pre-tax loss in 2010. See Note 11 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

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2010 vs. 2009

Revenue Analysis:

	Year ended December 31, 2010	2009	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$ 1,797	$ 1,916	$ (119)	(6)%
Natural gas liquid sales	282	136	146	107%
Oil and condensate sales	57	38	19	50%
Total product revenues, including sales to Williams	2,136	2,090	46	2%
Gas management, including sales to Williams	1,742	1,456	286	20%
Hedge ineffectiveness and mark to market gains and losses	27	18	9	50%
Other	40	39	1	3%
Total domestic revenues	$ 3,945	$ 3,603	$ 342	9%
Total international revenues	$ 89	$ 78	$ 11	14%
Total revenues	$ 4,034	$ 3,681	$ 353	10%

Domestic Revenues

Significant variances in comparative revenues reflect:

$119 million decrease in natural gas sales reflects realized average prices per Mcf price of $4.57 (including hedges) in 2010 compared to $4.59 in 2009. Production volumes were 392,776 MMcf in 2010 compared to 417,537 MMcf in 2009. Excluding the impact of hedges, our per Mcf price was $3.73 in 2010 compared to $3.12 in 2009.

$146 million increase in natural gas liquids reflects a per barrel price of $35.02 in 2010 compared to $28.80 in 2009. Volumes were 8,056 Mbbls in 2010 compared to 4,721 Mbbls in 2009. The volume increase reflects a full year of the Willow Creek plant which went into service in August 2009.

$19 million increase in oil and condensate reflects a per barrel price of $66.32 in 2010 compared to $47.39 in 2009. Volumes were 857 Mbbls in 2010 compared to 803 Mbbls in 2009.

A $286 million increase in 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 gas management costs and expenses.

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International Revenues

International revenues increased primarily due to higher average oil sales prices coupled with increased sales volumes.

Cost and operating expense and operating income (loss) analysis:

	Years ended December 31, 2010	2009	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating, including expenses with Williams	$ 267	$ 247	$ 20	8%
Gathering, processing and transportation, including expenses with Williams	326	273	53	19%
Taxes other than income	109	80	29	36%
Gas management (including charges for unutilized pipeline capacity)	1,771	1,495	276	18%
Exploration	67	53	14	26%
Depreciation, depletion and amortization	858	870	(12)	(1)%
Impairment of producing properties and costs of acquired unproved reserves	678	15	663	NM
Goodwill impairment	1,003		1,003	NM
General and administrative, including Williams	244	242	2	1%
Other net	(19)	32	(51)	NM
Total domestic costs and expenses	$ 5,304	$ 3,307	1,997	60%
International costs and expenses:				
Lease and facility operating	$ 19	$ 16	3	19%
Taxes other than income	16	13	3	23%
Exploration	6	1	5	NM
Depreciation, depletion and amortization	17	17		%
General and administrative	9	9		%
Other net		1	(1)	NM
Total international costs and expenses	$ 67	$ 57	$ 10	18%
Total costs and expenses	$ 5,371	$ 3,364	$ 2,007	60%
Domestic operating income (loss)	$ (1,359)	$ 296	$ (1,655)	NM
International operating income	$ 22	$ 21	$ 1	5%

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

Domestic Costs

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

$20 million higher lease and facility operating expenses due to increased activity and generally higher industry costs. Our lease and facility operating expenses averaged $0.60 per Mcfe in 2010 compared to $0.55 per Mcfe in 2009;

$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

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portion of our Piceance Basin gas production. Our average gathering, processing and transportation charges were $0.73 per Mcfe in 2010 compared to $0.60 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 Consolidated Statement of Operations;

$29 million higher taxes other than income, including severance and ad valorem, primarily due to higher average commodity prices (excluding the impact of hedges). Our taxes other than income averaged $0.24 per Mcfe in 2010 compared to $0.18 per Mcfe in 2009;

$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;

$14 million higher exploration expense primarily due to an increase in impairment, amortization and expiration of unproved leasehold costs;

$12 million lower depreciation, depletion and amortization expenses primarily due to lower natural gas domestic production volumes. Our depreciation, depletion and amortization expenses averaged $1.92 per Mcfe in 2010 compared to $1.93 per Mcfe in 2009;

$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;

Other-net in 2010 reflects a gain on sale of $12 million associated with a third-party sale of a portion of gathering and processing assets in the Piceance Basin and a $7 million gain on exchange of undeveloped leasehold acreage with a third party. Other net in 2009 includes $32 million of expenses in 2009 related to penalties from the early release of drilling rigs.

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International Costs

International costs and operating expense increases were primarily due to increased production and lifting costs associated with growth in operations. Additionally, exploratory expenses increased due to acquisition and processing of seismic information.

Consolidated results below operating income (loss)

	Years ended December 31, 2010	2009	$ Change	Percentage Increase (Decrease)
	(Millions)			
Consolidated operating income (loss)	$ (1,337)	$ 317	$ (1,654)	NM
Interest expense:				
Interest expense Williams	(119)	(92)	(27)	29%
Interest expense other	(5)	(8)	3	(38)%
Total interest expense, including Williams	(124)	(100)	(24)	24%
Interest capitalized	16	18	(2)	(11)%
Investment income and other	21	8	13	163%
Income (loss) from continuing operations before income taxes	(1,424)	243	(1,667)	NM
Provision (benefit) for income taxes	(149)	96	(245)	NM
Income (loss) from continuing operations	(1,275)	147	(1,422)	NM
Loss from discontinued operations	(8)	(7)	(1)	14%
Net income (loss)	(1,283)	140	(1,423)	NM
Less: Net income attributable to noncontrolling interests	8	6	2	33%
Net income (loss) attributable to WPX Energy	$ (1,291)	$ 134	$ (1,425)	NM

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

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

Investment income 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.

Provision (benefit) for income taxes changed due to the pre-tax loss in 2010 compared to pre-tax income in 2009. See Note 11 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Management s Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2011, we continued to focus upon growth through continued disciplined investments in expanding our natural gas, oil and NGL portfolio while executing our separation from Williams.

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

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place with Williams through June 30, 2011, at which time the notes were cancelled by Williams. Any cash activity from July 1, 2011 until November 30, 2011 was treated as capital contribution. On December 1, 2011 we began to manage our own cash beginning with the $500 million retained after the issuance of the Notes. In consideration of our liquidity, we note the following:

- As of December 31, 2011, we maintained liquidity through cash, cash equivalents and available credit capacity under our Credit Facility.
- 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

We expect our capital structure will provide us with financial flexibility to meet our requirements for working capital, capital expenditures and tax and debt payments while maintaining a sufficient level of liquidity. We retained approximately $500 million of the net proceeds from the issuance of the notes and have a $1.5 billion Credit Facility. These sources of liquidity along with our expected cash flows from operations should be sufficient to allow us to pursue our business strategy and goals for 2012 and 2013.

If energy commodity prices for 2012 and 2013 continue to trend lower, as they have done during early 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 2012 and 2013:

- Our capital expenditures are estimated to be approximately $1.2 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.

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, primarily resulting from lower energy commodity prices;
- Higher than expected collateral obligations that may be required, including those required under new commercial agreements;
- Significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold; and
- Reduced access to our Credit Facility

Under our Credit Facility, we are required to maintain a ratio of PV to Consolidated Indebtedness 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. Further declines in natural gas prices during future years could reduce our PV and thus limit our available capacity under the agreement. However, we believe that we have full access to the $1.5 billion in 2012 based on year-end pricing. See Note 10 of Notes to Consolidated Financial Statements.

We have executed three bilateral, uncommitted letter of credit agreements that we anticipate will be renewed annually. These agreements allow us to preserve our liquidity under our Credit Facility while providing

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support on our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility. At December 31, 2011 a total of $292 million in letters of credit have been issued with the potential for an additional $100 million in 2012 issuances.

Liquidity

We plan to conservatively manage our balance sheet. Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2012. Our internal and external sources of consolidated liquidity include cash generated from operations, cash and cash equivalents on hand, and our Credit Facility. Additional sources of liquidity, if needed and if available, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales.

Credit Ratings

Our ability to borrow money will be impacted by several factors, including our credit ratings. Credit ratings agencies perform independent analyses when assigning credit ratings. A downgrade of our current rating could increase our future cost of borrowing and result in a requirement that we post additional collateral with third parties, thereby negatively affecting our available liquidity. The current ratings are as follows:

Standard and Poor s(1)	
Corporate Credit Rating	BB+
Senior Unsecured Debt Rating	BB+
Outlook	Stable
Moody s Investors Service(2)	
Senior Unsecured Debt Rating	Ba1
Outlook	Stable

(1) A rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

(2) A rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1, 2, and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates the lower end of the category.

Additionally, under the Credit Facility, prior to our receipt of an investment grade rating with a stable outlook, we will be required to maintain a ratio of net present value of projected future cash flows from Proved Reserves to Consolidated Indebtedness (each as defined in the Credit Facility) of at least 1.50 to 1.00. The net present value is determined as of the end of each fiscal year and reflects the present value, discounted at nine percent, of projected future cash flows of domestic proved oil and gas reserves (with a limitation of no more than 35 percent that are not proved developed producing reserves), based on lender-projected commodity price assumptions and after giving effect to hedge arrangements. It is possible that in the future our present value ratio calculation could result in limiting our full use of the $1.5 billion Credit Facility. Even if such a limitation were to occur, we believe our sources of liquidity will be sufficient for us to pursue our anticipated capital spending plans.

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Sources (Uses) of Cash

The following table and discussion summarize our sources (uses) of cash for the years ended December 31, 2011, 2010 and 2009.

	Years Ended December 31,		
	2011	2010	2009
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 1,206	$ 1,056	$ 1,181
Investing activities	(1,556)	(2,337)	(1,435)
Financing activities	839	1,284	256
Increase in cash and cash equivalents	$ 489	$ 3	$ 2

Operating activities

Our net cash provided by operating activities in 2011 increased from 2010 primarily due to net favorable changes in our operating assets and liabilities compared to 2010.

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.

Investing activities

Our net cash used by investing activities in 2011 decreased from 2010 primarily due to reduced capital expenditures and the absence of our acquisitions in 2010 for Marcellus Shale and Bakken Shale properties.

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 items include:

2011

Expenditures for drilling and completion were approximately $1.4 billion.

2010

Expenditures for drilling and completion were approximately $950 million.

Our acquisition in July 2010 of properties in the Marcellus Shale for $599 million.

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

The sale in November 2010 of certain gathering and processing assets in the Piceance Basin to Williams Partners for $702 million in cash ($244 million of which was in excess of our net book value and thus a financing and capital transaction with Williams) 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.

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Financing activities

Our net cash from financing activities decreased in 2011 primarily due to distribution to Williams of approximately $981 million from our $1.5 billion in note proceeds in November offset by lower borrowings from Williams in 2011 compared to 2010.

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 December 31, 2011 and December 31, 2010.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2011, including obligations related to discontinued operations.

	2012	2013 - 2014	2015 - 2016 (Millions)	Thereafter	Total
Long-term debt, including current portion					
Principal	$ 1	$ 2	$	$ 1,500	$ 1,503
Interest	58	175	174	374	781
Operating leases and associated service commitments					
Drilling rig commitments(1)	153	219	38		410
Other	14	18	18	35	85
Transportation and storage commitments(2)	215	388	316	489	1,408
Natural gas purchase commitments(3)	82	305	319	744	1,450
Oil and gas activities(4)	237	257	155	199	848
Other	22	19	11		52
Other long-term liabilities, including current portion:					
Physical and financial derivatives(5)	457	615	671	2,831	4,574
Total	$ 1,239	$ 1,998	$ 1,702	$ 6,172	$ 11,111

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

(2) Excludes additional commitments totaling $601 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 December 31, 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 Williams Partners. WPX Energy s gas purchase obligations amounting to $1.4 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 $302 million as of December 31, 2011. The ultimate settlement and timing can not be precisely determined in advance; however, we estimate that approximately 11% of this liability will be settled in the next five years.

(5) Includes $4.5 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

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obligation. The obligations for physical and financial derivatives are based on market information as of December 31, 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.

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.

Environmental

Our operations are subject to governmental laws and regulations relating to the protection of the environment, and increasingly strict laws, regulations and enforcement policies, as well as future additional environmental requirements, could materially increase our costs of operation, compliance and any remediation that may become necessary.

We are subject to the Clean Air Act (CAA). 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 included 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 established specific new requirements regarding emissions from wells (including 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 established new leak detection requirements for natural gas processing plants. The EPA adopted the proposed rules and published the final rules on April 18, 2012. As finalized, these rules as they are phased in will require certain 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.

On November 30, 2010, the EPA issued its final rule expanding the scope of the Greenhouse Gas (GHG) Mandatory 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 will be required on an annual basis, with reporting beginning in March 2012 for emissions occurring in 2011. We are required to report our GHG emissions by March 2012 under this rule. Several of EPA s GHG rules are being challenged in court proceedings and depending on their outcome, such rules may be modified, rescinded or the EPA could develop new rules. Compliance with such rules could result in significant costs.

Our facilities and operations are also subject to the Clean Water Act (CWA) and implementing regulations of the EPA and the United States 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 States to all CWA provisions, which prior guidance limited to Section 404 determinations. EPA and the Corps anticipate proposing a rule for final comment in 2012. We are unable at this time to estimate the cost that may be required to meet the proposed guidance or any related final rules.

There have been multiple legislative and regulatory initiatives relating to hydraulic fracturing that could also result in increased costs and additional operating restrictions or delays. 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 enact separate federal legislation or legislation at the state and local government levels to regulate hydraulic fracturing. 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. The EPA has 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. In October 2011, the EPA announced that it intends to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board in August 2011 also issued a report on hydraulic fracturing, 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 United States 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 the National Environmental Policy Act (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, New Mexico and Oklahoma). The United States Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing, which, if adopted, would affect our operations on federal lands. Compliance with such legislation or regulations could result in significant costs, including increased capital expenditures and operating cost, and could also cause delays, or eliminate certain drilling and injection activities, all of which could adversely impact our business.

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 as follows:

Impairments of Long-Lived Assets

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 undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset, and the current and future economic environment in which the asset is operated.

Due to the drop in natural gas forward prices during the fourth quarter of 2011, 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. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The assessment performed identified certain properties with a carrying

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value in excess of those undiscounted cash flows and their calculated fair values. As a result, we recognized $547 million of impairment charges. See Notes 7 and 16 of Notes to Consolidated 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 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 consolidated financial statements. For other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately eight percent could be at risk for impairment if forward prices across all future periods decline by approximately 12 percent to 15 percent, on average, as compared to the forward prices at December 31, 2011. A substantial portion of the remaining carrying value of these other assets could be at risk for impairment if forward prices across all future periods decline by at least 24 percent, on average, as compared to the prices at December 31, 2011.

Accounting for Derivative Instruments and Hedging Activities

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we will begin entering into commodity derivative contracts that will continue to serve as economic hedges but will not be designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2011 that are included in accumulated other comprehensive income have been and will continue to be transferred to earnings during the same periods in which the forecasted hedged transactions are recognized.

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. 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:

	Consolidated Statement of Operations		**Consolidated 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 15 of Notes to Consolidated 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.

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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 99 percent of our domestic reserves 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 reserves 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 $81 million and $99 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 reserves 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. Our lease acquisition costs totaled $1.1 billion at December 31, 2011.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including royalty litigation, environmental and other contingent 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 12 of Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Liabilities

Through the effective date of the spin-off, our domestic operations were 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 for us and our consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected benefit to us could not be determined until the date of deconsolidation.

The determination of our effective state tax rate requires judgment as we did not exist as a stand-alone filer during these periods and the effective state tax rate can change periodically based on changes in our operations.

Our effective state tax rate is based upon our current entity structure and the jurisdictions in which we operate. If the effective state tax rate were to be revised upward by one-tenth of one percent, this would result in an increase to our net deferred income tax liability of approximately $3 million.

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of book basis, from certain separate state losses generated in the current and prior years and, effective with the spin-off, from certain tax attributes allocated between us and Williams. We must periodically evaluate whether it is more likely than not we will realize these tax benefits and establish a valuation allowance for those that that do not meet the more likely than not threshold. 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.

See Note 11 of Notes to Consolidated 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, 2011, 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, 2011, the credit reserve is less than $1 million 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, 2011, 99 percent of the fair value of our derivatives portfolio expires in the next 12 months and approximately 100 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, 2011, 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.

For the years ended December 31, 2011 and 2010, 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 15 of Notes to Consolidated Financial Statements.

BUSINESS

Separation from the Williams Companies, Inc.

On December 31, 2011 (the Distribution Date), WPX Energy, Inc. became an independent, publicly traded company as a result of a distribution by Williams of its shares of WPX to Williams stockholders. On the Distribution Date, Williams stockholders of record as of the close of business on December 14, 2011, the spin-off record date, received one share of WPX common stock for every three shares of Williams common stock held as of the Record Date (the Distribution). WPX is comprised of Williams former natural gas and oil exploration and production business. Williams Board of Directors approved the distribution of its shares of WPX on November 30, 2011. WPX was incorporated on April 19, 2011 to effect the Distribution. Our registration statement on Form 10 was declared effective by the U.S. Securities and Exchange Commission on December 5, 2011. Our common stock began trading regular-way under the ticker symbol WPX on the New York Stock Exchange on January 3, 2012.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is (855) 979-2012.

WPX Energy, Inc.

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 reserves 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 an approximate 69 percent controlling ownership interest in Apco Oil and Gas International Inc., 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 four 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. Our proved reserves at December 31, 2011 were 5,265 Bcfe, comprised of 5,070 Bcfe in domestic reserves and 195 Bcfe in net international reserves. Our domestic reserves reflect a mix of 77.4 percent natural gas, 15.4 percent NGLs and 7.2 percent crude oil. During 2011, we replaced our domestic production for all commodities at a rate of 188 percent. For liquids alone, we replaced 488 percent of our crude and NGL production. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

We report financial results for two segments, our Domestic segment and our International segment. Our International segment primarily consists of Apco. Except as otherwise specifically noted, either by a reference to Apco or to other international operations, the following description of our business is focused on our Domestic segment, which is our dominant segment and which is central to an understanding of our business taken as a whole.

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 2012 we demonstrated our capital discipline by announcing our plans to reduce drilling expenditures in response to prevailing natural gas prices and direct our expenditures toward our oil and liquids-rich areas.

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 expect to 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. 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 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 derivative 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 December 31, 2011, our estimated domestic natural gas production revenues were 53 percent hedged for 2012. Estimated domestic oil production revenues were 66 percent hedged for 2012 and 10 percent hedged for 2013 as of the same date.

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.

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.

During 2011, we operated an average of 11 drilling rigs in the basin, including nine in the Piceance Valley and two in the Piceance Highlands. In the current commodity price environment, we expect a reduced number of

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rigs in 2012. We had an average of 679 MMcf/d of net gas production from our Piceance Basin properties along with an average of 27.1 Mbbls/d of NGLs and 2.3 Mbbls/d of condensate recovered from our Piceance Basin properties. Capital expenditures were approximately $739 million which included the completion of 385 gross (361 net) wells in 2011. A large majority of our natural gas production in this basin currently is gathered through a system owned by Williams Partners L.P. (Williams Partners) and delivered to markets through a number of interstate pipelines.

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.

Bakken Shale

In December 2010 we acquired leasehold positions of 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 are 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.

During 2011, we operated an average of 3.4 rigs on our Bakken properties and we had an average of 5.2 Mboe/d of net production from our Bakken Shale wells. Capital expenditures were approximately $288 million which included the completion of 25 gross (20 net) wells in 2011.

We are developing oil reserves through horizontal drilling in the Middle Bakken and plan to develop the 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.

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.

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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 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, National Environmental Policy Act, 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. (See Management s Discussion and Analysis of Financial Condition and Results of Operations Overview for discussion of a $50 million write-off of leasehold costs associated with approximately 65 percent of our total Columbia County acreage. Our total Columbia County acreage represents 21 percent of our total undeveloped acreage in the Marcellus Shale). We have expanded 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 was completed in December 2011.

During 2011, we operated an average of four rigs on our Marcellus Shale properties and we had an average of 15 MMcfe/d of net production from our Marcellus Shale wells. Production levels were hampered for much of 2011 awaiting the completion of a third-party gathering system. Capital expenditures were approximately $274 million which included the completion of 38 gross (19 net) wells in 2011. At year end, another 27 gross wells were awaiting completion.

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.

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 912,056 acres, of which our ownership represents 411,440 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.

During 2011, we had an average of 227 MMcfe/d of net production from our Powder River Basin properties. Capital expenditures were approximately $57 million which included the completion of 524 gross (226 net) wells in 2011. The majority of these wells were drilled in prior years and completed the dewatering process in 2011. In 2012, we expect our expenditures to be significantly less than our 2011 expenditures.

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 Company 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 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.

During 2011, we had an average of 136 MMcfe/d of net production from our San Juan Basin properties. Capital expenditures were approximately $58 million which included the completion of 56 gross (33 net) wells.

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. 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.

International

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 three 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.

During 2011, Apco had an average of 12.9 Mboe/d of net production.

Apco participated in the drilling of 33 wells operated by its partners in 2011 of which Apco spent, for its direct ownership interest, approximately $39 million in capital expenditures.

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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.

We also hold additional international assets in northwest Argentina that are not part of Apco s holdings.

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, and interests in the Arkoma Basin in southeastern Oklahoma.

During 2011, we operated one rig on our other properties and we had an average of 78 MMcfe/d of net production from continuing operations from our other properties. Capital expenditures were approximately $118 million, which included the completion of 212 gross (34 net) wells on our other properties in 2011. In 2012, we expect our capital expenditures to be significantly less than 2011 for these basins.

Our Barnett Shale properties produce predominately natural gas from horizontal wells, where we are the primary operator and have drilled more than 200 wells. We are seeking offers to sell our Arkoma Basin properties, which include 79,110 net acres, including 22,728 undeveloped net acres. Such properties were reported as discontinued operations in our consolidated financial statements and comprised less than one percent of our assets and are not included in our average daily net production amount for 2011.

Acquisitions and Divestitures

Our acquisitions during 2011 consisted of miscellaneous leasehold purchases with minimal associated production. We may from time to time dispose of producing properties and undeveloped acreage positions if we believe they no longer fit into our strategic plan.

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.

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 four 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.

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Oil and Gas Reserves

Our proved reserves were previously reported on a combined product basis, however, with the increase in the significance of our oil and natural gas liquids reserves estimates, we have separated our reserves estimates into natural gas, natural gas liquids and oil. As a result, previously reported periods have been recast to reflect current presentation. The following table sets forth our estimated domestic net proved developed and undeveloped reserves expressed by product and on a gas equivalent basis for the reporting periods December 31, 2011, 2010 and 2009.

	As of December 31, 2011				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(2)	%
Proved Developed	2,497,291	72,139	13,555	3,011,457	59%
Proved Undeveloped	1,485,644	61,938	33,568	2,058,676	41%
Total Proved-Domestic	3,982,935	134,077	47,123	5,070,133	

	As of December 31, 2010(1)				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(2)	%
Proved Developed	2,368,465	48,688	3,973	2,684,431	58%
Proved Undeveloped	1,545,739	47,169	20,302	1,950,567	42%
Total Proved-Domestic	3,914,204	95,857	24,275	4,634,998	

	As of December 31, 2009(1)				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(2)	%
Proved Developed	2,298,420	31,570	1,914	2,499,329	56%
Proved Undeveloped	1,771,279	32,463	2,728	1,982,422	44%
Total Proved-Domestic	4,069,699	64,033	4,642	4,481,751	

(1) NGL amounts for 2010 and 2009 were previously reported as part of natural gas production volumes at the wellhead.
(2) Oil and NGLs converted to MMcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

The following table sets forth our estimated domestic net proved reserves for our largest areas of activity expressed by product and on a gas equivalent basis as of December 31, 2011.

	As of December 31, 2011			
	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Equivalent (MMcfe)
Piceance Basin	2,689,440	128,594	5,760	3,495,567
Bakken Shale	19,838	3,910	40,627	287,056
Marcellus Shale	141,865			141,865
Powder River Basin	343,795	20	50	344,214
San Juan Basin	531,080	581	66	534,963
Other	256,917	972	620	266,468

Total Proved-Domestic	3,982,935	134,077	47,123	5,070,133

We prepare our own reserves estimates and approximately 99 percent of our reserves are audited by Netherland, Sewell & Associates, Inc. (NSAI).

We have not filed on a recurring basis estimates of our total proved net oil, NGL, 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.

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Our 2011 year-end estimated proved reserves were derived using an average price of $3.64 per Mcf, an average oil price of $86.87 per barrel and average NGL price of $49.30 per barrel. These prices were calculated from the 12-month average, first-of-the-month price for the applicable indices for each basin as adjusted for locational price differentials. During 2011, we added 1,065 Bcfe of additions to our proved reserves. During 2011, we participated in the drilling of 1,241 gross wells at a capital cost of approximately $1,461 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 NSAI and the asset teams to successfully complete the 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 NSAI 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 NSAI. In early December, reserves are reviewed with senior management. The process concludes upon receipt of the audit letter from NSAI.

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 99 percent of our total year-end 2011 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, 2011 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.

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 29 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 general, 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, 2011, our proved undeveloped reserves were 2,059 Bcfe, an increase of 108 Bcfe over our December 31, 2010 proved undeveloped reserves estimate of 1,951 Bcfe. During 2011, 321 Bcfe of our December 31, 2010 proved undeveloped reserves were converted to proved developed reserves at a cost of $587 million. An additional 306 Bcfe was added due to the development of unproved locations. As of 2011 year-end, we have reclassified a net 502 Bcfe from proved to probable reserves due to the SEC five year rules. These reclassified reserves are predominately in the Piceance Basin where we have a large inventory of drilling locations and have been offset by the combined additions and revisions of 671 Bcfe of proved undeveloped drilling locations.

All proved undeveloped locations are scheduled to be spud within the next five years.

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

Our production sales data was previously reported on a combined product basis, however, with the increase in the significance of our oil and natural gas liquids production, we have separated our production sales data into natural gas, natural gas liquids and oil. As a result, previously reported periods have been recast to reflect current presentation. The following table summarizes our net production sales for the years indicated.

	Year Ended December 31,		
	2011	**2010**	**2009**
Production Sales Data:			
Natural Gas (MMcf)			
U.S.			
Piceance Basin	247,700	230,279	245,946
Other(1)	165,820	162,497	171,591
International(2)	7,389	7,088	6,789
Total	420,909	399,864	424,326
NGLs (Mbbls)			
U.S.			
Piceance Basin	9,902	8,003	4,644
Other(1)	156	53	77
International(2)	183	162	154
Total	10,241	8,218	4,875
Oil (Mbbls)			
U.S.	2,676	857	803
International(2)	2,054	1,980	1,994
Total	4,730	2,837	2,797
Combined Equivalent Volumes (MMcfe)(2)(3)	510,735	466,194	470,354
Combined Equivalent Volumes (Mboe)	85,122	77,699	78,392
Average Daily Combined Equivalent Volumes (MMcfe/d)(3)			
U.S.			
Piceance Basin	855	775	761
Other(1)	487	448	474
International(2)	57	55	51
Total	1,399	1,278	1,286

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(1) Excludes production from our Arkoma Basin operations which were classified as held for sale and reported as discontinued operations 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.
(3) Amounts for 2010 and 2009 have been recalculated using a conversion ratio for our NGLs of 6 to 1 as these were previously reported in natural gas volumes.

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

	Year Ended December 31,		
	2011	2010	2009
Realized average price per unit(1):			
Natural gas, without hedges (per Mcf)	$ 3.51	$ 3.73	$ 3.12
Impact of hedges (per Mcf)	0.79	0.84	1.47
Natural gas, with hedges (per Mcf)	$ 4.30	$ 4.57	$ 4.59
NGL, without hedges (per Bbl)	$ 40.17	$ 35.02	$ 28.80
Impact of hedges (per Bbl)			
NGL, with hedges (per Bbl)	$ 40.17	$ 35.02	$ 28.80
Oil, without hedges (per Bbl)	$ 85.00	$ 66.32	$ 47.39
Impact of hedges (per Bbl)	0.38		
Oil, with hedges (per Bbl)	$ 85.38	$ 66.32	$ 47.39
Price per Boe, without hedges(2)	$ 25.53	$ 24.24	$ 19.63
Price per Boe, with hedges(2)	$ 29.53	$ 28.71	$ 27.82
Price per Mcfe, without hedges(2)	$ 4.26	$ 4.04	$ 3.27
Price per Mcfe, with hedges(2)	$ 4.92	$ 4.79	$ 4.64

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations and comprised less than one percent of our total revenues.
(2) Realized average prices reflect realized market prices, net of fuel and shrink.

	Year Ended December 31,		
	2011	2010	2009
Expenses per Mcfe(1):			
Operating expenses:			
Lifting costs and workovers	$ 0.46	$ 0.42	$ 0.37
Facilities operating expense	0.04	0.13	0.14
Other operating and maintenance	0.05	0.05	0.04

Total LOE	$ 0.55	$ 0.60	$ 0.55
Gathering, processing and transportation charges	1.02	0.73	0.60
Taxes other than income	0.24	0.24	0.18
Production cost	$ 1.81	$ 1.57	$ 1.33
General and administrative	$ 0.56	$ 0.55	$ 0.54
Depreciation, depletion and amortization	$ 1.89	$ 1.92	$ 1.93

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

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Productive Oil and Gas Wells

The table below summarizes 2011 productive wells by area.*

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance Basin	4,278	3,908		
Bakken Shale			59	35
Marcellus Shale	54	29		
Powder River Basin	6,760	3,007		
San Juan Basin	3,289	888		
Other(1)	1,834	551		
Total	16,215	8,383	59	35

* 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 are classified as held for sale and reported as discontinued operations and comprised less than one percent of our assets.

At December 31, 2011, there were 221 gross and 110 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2011.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance Basin	121,101	96,668	155,538	116,300	276,639	212,968
Bakken Shale	36,494	31,054	58,591	55,059	95,085	86,113
Marcellus Shale(1)	12,831	7,026	125,861	99,950	138,692	106,976
Powder River Basin	609,995	277,726	302,061	133,715	912,056	411,441
San Juan Basin	240,091	121,925	2,100	1,576	242,191	123,501
Other(2)	153,114	84,870	240,310	155,737	393,424	240,607
Total	1,173,626	619,269	884,461	562,337	2,058,087	1,181,606

(1) Approximately 21 percent of our undeveloped net acres in the Marcellus Shale are located in Columbia County. During 2011, we recorded a $50 million write-off of leasehold costs associated with approximately 65 percent of our Columbia County acreage that we no longer plan to develop.

(2) 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 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 2011, 2010 and 2009.

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The following table summarizes the number of domestic wells drilled for the periods indicated.

	2011		2010		2009	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance Basin	385	361	398	360	363	334
Bakken Shale	25	20			n/a	n/a
Marcellus Shale	36	17	8	3	2	1
Powder River Basin	523	225	531	244	540	244
San Juan Basin	56	33	43	15	87	50
Other	212	34	177	38	199	36
Productive, development	1,237	690	1,157	660	1,191	665
Productive, exploration	2	2			1	
Total Productive	1,239	692	1,157	660	1,192	665
Dry, development	2	1	5	4	2	1
Dry, exploration					2	1
Total Drilled	1,241	693	1,162	664	1,196	667

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties.
In 2011, we drilled two gross nonproductive development wells (in Marcellus Shale and in Powder River Basin) and one net nonproductive development wells. Total gross operated wells drilled were 758 in 2011, 656 in 2010 and 472 in 2009.

Present Activities

At December 31, 2011, we had 25 gross (17 net) wells in the process of being drilled.

Scheduled Lease Expirations

Domestic. The table below sets forth, as of December 31, 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 59% of the acreage shown in the table below as Other in 2012 through 2013 consists of our Arkoma Basin operations which are currently held for sale.

	2012	2013	2014	2015 +	Total
Piceance Basin	4,777	2,878	489	2,522	10,666
Bakken Shale	9,620	43,362	370	1,639	54,991
Marcellus Shale	890	35,839	6,579	43,674	86,982
Powder River Basin	8,106	15,382	1,081	66	24,635
San Juan Basin					
Other	11,692	13,523	28,760	81,037	135,012
Total (Gross Acres)	35,085	110,984	37,279	128,938	312,286

	2012	2013	2014	2015+	Total
Piceance Basin	2,104	2,182	649	2,104	7,039
Bakken Shale	9,224	42,835	370	1,535	53,964
Marcellus Shale	787	27,934	3,974	38,369	71,064

Powder River Basin	2,715	7,474	547	52	10,788
San Juan Basin					
Other	9,761	12,487	27,887	81,033	131,168
Total (Net Acres)	24,591	92,912	33,427	123,093	274,023

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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 approximate 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 2012 and 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 include the sale of our natural gas, NGL and oil production, in addition to third-party purchases and subsequent sales to Williams Partners for fuel and shrink gas. 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 December 2010, we agreed to buy up to 200,000 MMBtu/d of natural gas at Transco Station 515 (Marcellus Shale) priced at market prices from a third party. Purchases under the 12-year contract began in January 2012. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

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.

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Hedging Activity

To manage the commodity price risk and volatility associated with owning producing natural gas, NGL and crude oil 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, NGLs and natural 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 2011, natural gas sales to BP Energy Company accounted for approximately 11 percent of our consolidated 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.

Regulatory Matters

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.

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;

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- 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 natural 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. Most states have an administrative agency that requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The United States Army Corps of Engineers 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 natural 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 them. 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 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.

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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 natural 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, and local 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 often 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

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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.

Environmental Matters

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 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

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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 corresponding common law 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 February 16, 2012, the EPA issued the final 2012 construction general permit (CGP) for stormwater discharges from construction activities involving more than one acre, which will provide coverage for a five year period. The 2012 CGP modifies the prior CGP to implement the new Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The new rule includes new and more stringent restrictions on erosion and sediment control, pollution prevention and stabilization, although a numeric turbidity limit for certain larger construction sites has been stayed as of January 4, 2011.

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 ordinarily 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. Our net acreage position in the basins in which hydraulic fracturing is utilized total approximately 770,000 acres and represents approximately 93% of our domestic proved undeveloped oil and gas reserves. Although average drilling and completion costs for each basin

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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 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, we observe regulatory requirements and what we consider best practices 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. Industry worked with the Colorado Oil & Gas Association as well as the COGCC to adopt a voluntary baseline groundwater quality sampling program. We have committed to the program that went into effect in August 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 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

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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 more than 430 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.

In 2011, we used 100% recycled water for our hydraulic fracturing operations in our largest area of development, the Piceance basin. This recycling process lessens the demand on local natural water resources. Any water that is recovered in our operations that is not used for our hydraulic fracturing operations is safely disposed in accordance with the State and Federal rules and regulations in a manner that does not impact underground aquifers and surface waters. In the Marcellus we use a blend of recycled water from our hydraulic fracturing operations with water from natural sources.

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 regulation 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 December 13, 2011, the Texas Railroad Commission adopted Statewide Rule 29, which requires public disclosure of the chemicals that operators use during hydraulic fracturing in Texas for all operators that receive a permit on or after February 1, 2012. 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. Colorado adopted its final hydraulic fracturing chemical disclosure rules on December 13, 2011. 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 7, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health 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. EPA issued a final rule that went into effect in 2011 that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions. 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 and 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.

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.

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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.

Employees

At December 31, 2011, we had approximately 1,200 full-time employees.

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DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

This section presents biographical information and other information about each of our executive officers (other than Mr. Hill, whose biographical information appears below under Board of Directors).

	Biographical Information
James J. Bender **Age 55** **Senior Vice President and General Counsel**	Mr. Bender was named General Counsel in April 2011. Mr. Bender served previously as Senior Vice President and General Counsel of The Williams Companies, Inc., or 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 2000 to June 2002, Mr. Bender was Senior Vice President and General Counsel of NRG Energy, Inc. Mr. Bender was Vice President, General Counsel, and Secretary of NRG Energy from June 1997 to June 2000. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.
Neal A. Buck **Age 56** **Senior Vice President of Business Development and Land**	Mr. Buck was named Senior Vice President of Business Development and Land in August 2011. Mr. Buck served previously as 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.
Michael R. Fiser **Age 47** **Senior Vice President of Marketing**	Mr. Fiser was named Senior Vice President of Marketing in August 2011. Mr. Fiser previously served as Vice President and Director of Williams Gas Marketing, Inc. since May 2008. His responsibilities include 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.

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	Biographical Information
Bryan K. Guderian **Age 52** **Senior Vice President of Operations**	Mr. Guderian was named Senior Vice President of Operations in August 2011. Mr. Guderian previously served as Vice President of the Exploration & Production unit of Williams since 1998. Mr. Guderian has 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 Oil & Gas International Inc., or 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.
Marcia M. MacLeod **Age 59** **Senior Vice President of Human Resources and Administration**	Ms. MacLeod was named Senior Vice President of Human Resources and Administration in August 2011. Ms. MacLeod previously 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.
Steven G. Natali **Age 57** **Senior Vice President of Exploration**	Mr. Natali was named Senior Vice President of Exploration in August 2011. Mr. Natali previously 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.
Rodney J. Sailor **Age 53** **Senior Vice President, Chief Financial Officer and Treasurer**	Mr. Sailor was named Treasurer and Deputy Chief Financial Officer in April 2011, and Chief Financial Officer in December 2011. Mr. Sailor previously 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.

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	Biographical Information
J. Kevin Vann **Age 40** **Chief Accounting Officer and Controller**	Mr. Vann was named Chief Accounting Officer and Controller in August 2011. Mr. Vann previously served as Controller for Williams Exploration & Production business unit since June 2007. 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 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 of Directors

This section presents biographical and other information about our directors. For each director, this section presents the specific experience, qualification and skills that helped lead our Board of Directors, or Board, to conclude that the individual should serve as a director.

Our Corporate Governance Guidelines set forth criteria for independent director nominees, including the following:

- An understanding of business and financial affairs and the complexities of a business organization. Although a career in business is not essential, the nominee should have a proven record of competence and accomplishments through leadership in industry, education, the professions or government, and should be willing to maintain a committed relationship with the Company as a director.

- A genuine interest in representing all of the shareholders and the interest of the Company overall.

- A willingness and ability to spend the necessary time to function effectively as a director.

- An open-minded approach to matters and the resolve to independently analyze matters presented for consideration.

- A reputation for honesty and integrity beyond question.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
William G. Lowrie **Age 68** **Director since 2011**	Mr. Lowrie was elected as Chairman of our Board of Directors in December 2011. Mr. Lowrie served as a director of Williams from 2003 until December 2011, and served as a member of Williams Audit Committee and its 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.	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 is advantageous to us as a new public company.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
Kimberly S. Bowers **Age 47** **Director since 2011**	Ms. Bowers has served since October 2008 as Executive Vice President and General Counsel for Valero Energy Corporation (a large independent refiner of transportation fuels and related products) with responsibility over Valero s legal, ad valorem tax, health, safety and environmental, energy and gases, reliability, and project execution departments. She joined Valero in 1997 as Corporate Counsel. From April 2006 to October 2008, she served as Senior Vice President & General Counsel. She has served as lead attorney for most of Valero s major acquisitions during her tenure with Valero.	We believe that Ms. Bowers is well qualified to serve as a member of our Board. Her executive experience and familiarity with legal and regulatory issues, including expertise on complex health, safety and environmental matters, will be critical to her ability to identify, understand and address challenges and opportunities that we face. Her experience as lead attorney for complex transactions well positions her to advise on any transactions that we may consider. As a result of her executive experience, Ms. Bowers also has an understanding of compensation and corporate governance issues that we face.
John A. Carrig **Age 60** **Director since 2011**	Mr. Carrig is the former President and Chief Operating Officer of ConocoPhillips (a large integrated oil company with operations in more than 30 countries). He joined Phillips Petroleum in London in 1978 as a tax attorney. In 1981, he transferred to Bartlesville, Oklahoma, and was associated with the corporate tax staff until 1993 when he joined the treasury group as finance manager. He was then named Assistant Treasurer of Finance, and in 1995 he accepted the position of Treasurer. He was Vice President and Treasurer from 1996 to 2000 when he was named Senior Vice President and Treasurer. He was elected Senior Vice President and Chief Financial Officer for Phillips in 2001, a position he held until the ConocoPhillips merger occurred in 2002, at which time he became Executive Vice President, Finance, and Chief Financial Officer of ConocoPhillips. In 2008, he was appointed President and Chief Operating Officer of ConocoPhillips and became responsible for global operations, including exploration and production, refining and transportation, project development and procurement, and health, safety and environmental matters. Mr. Carrig served as President of ConocoPhillips until his retirement in March 2011.	We believe Mr. Carrig is well qualified to serve as a member of our Board. Mr. Carrig 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 face. Mr. Carrig also has expertise leading a public company with multi-national operations, which is advantageous to us as a new public company with multi-national operations.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
William R. Granberry **Age 69** **Director since 2011**	Mr. Granberry served as a director of Williams from 2005 until December 2011, and served as a member of Williams Compensation Committee and its Finance Committee. Mr. Granberry has been a member of Compass Operating Company LLC (a small, private oil and gas exploration, development, and producing company) since October 2004. From 1999 to 2004, as an independent consultant, he managed investments and consulted with oil and gas companies. From 1996 to 1999, Mr. Granberry was President and Chief Operating Officer of Tom Brown, Inc. (a public oil and gas company with exploration, development, acquisition, and production activities throughout the central United States). He has worked in the oil and gas industry in various capacities for 45 years, including as a manager of engineering at Amoco (a global energy company) and in executive positions for smaller independent energy companies. Mr. Granberry has served on committees and boards of industry organizations, including the Society of Petroleum Engineers, the American Petroleum Institute, and the Independent Producers Association of America. A start up Internet company, Just4Biz.com, where he served on the board of directors and as interim chief executive officer for periods in 2000 and 2001, filed for bankruptcy in May 2001. Since January 2008, he has been a director of Legacy Reserves GP, LLC (an independent acquirer and developer of oil and natural gas properties) and a trustee of Manor Park, Inc.	We believe Mr. Granberry is well qualified to serve as a member of our Board. Mr. Granberry has many years of experience in our industry, including executive, investment and operating experience, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we face. Mr. Granberry also has extensive public policy experience from serving on committees and boards of industry organizations. Further, we believe Mr. Granberry s experience as a director of Williams is advantageous to us as a new public company.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
Don J. Gunther **Age 73** **Director since 2011**	In 1999, Mr. Gunther retired as Vice Chairman and Director of the Bechtel Group, Inc. (an engineering, construction and project management company) where he spent his entire 39-year career. As Vice Chairman, Mr. Gunther had responsibility for all of the global industry units and for all corporate functions including project management, engineering, procurement, construction, information services, information technology and contracts. Mr. Gunther held various positions of increasing responsibility during his time at the Bechtel Group, including field engineer, leader of worldwide construction for refinery and chemical projects, senior vice president, and president of Bechtel, Petroleum, Chemical & Industrial Company, president of Bechtel s Europe, Africa, Middle East, and Southwest Asia region and president of Bechtel s Americas organization. Since 2007, Mr. Gunther has served as Chairman of Ingage (a private high tech company and enterprise networking organization). Mr. Gunther is also currently the chairman of the board of directors of Immokalee Foundation (a non-profit organization helping immigrant underprivileged children) and the Gulf Shore Playhouse, and is a board member and part owner of Imperial Homes (a home building company based in Naples, Florida).	We believe Mr. Gunther is well qualified to serve as a member of our Board. Mr. Gunther has significant engineering, operating and executive experience, and we believe this experience will be critical to his ability to identify, understand and address challenges and opportunities that we face. Mr. Gunther also has expertise leading a company with multi-national operations, which is advantageous to us as a new public company with multi-national operations.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
Robert K. Herdman **Age 63** **Director since 2011**	Since 2004, Mr. Herdman has been a Managing Director of Kalorama Partners LLC (a Washington, D.C. consulting firm specializing in providing advice regarding corporate governance, risk assessment, crisis management and related matters). Prior to joining Kalorama, Mr. Herdman was the Chief Accountant of the SEC from October 2001 to November 2002. Prior to joining the SEC, he was Ernst & Young s Vice Chairman of Professional Practice for its Assurance and Advisory Business Services (AABS) practice in the Americas and the Global Director of AABS Professional Practice for Ernst & Young International. Mr. Herdman was also the senior Ernst & Young partner responsible for the firm s relationship with the SEC, Financial Accounting Standards Board and American Institute of Certified Public Accountants (AICPA). Mr. Herdman served on the AICPA s SEC Practice Section Executive Committee from 1995 to 2001 and as a member of the AICPA s Board of Directors from 2000 to 2001. Mr. Herdman is currently on the board of directors of Cummins Inc. and is chair of its audit committee. He is also currently on the board of directors and chairs the audit committee of HSBC Finance Corporation (formerly Household International, Inc.), HSBC North America Holdings, Inc. and HSBC US, Inc. These HSBC entities belong to a single controlled group of corporations and their boards of directors and audit committees conduct their meetings simultaneously.	We believe Mr. Herdman is well qualified to serve as a member of our Board. Mr. Herdman has significant experience in finance and accounting, including expertise as the chair of the audit committees for public companies, and we believe these experiences will be important to his ability to understand and address challenges and opportunities that we face. Mr. Herdman s SEC and public accounting experience provided Mr. Herdman with insight into the business operations and financial performance of a significant number of public companies, which is advantageous to us as a new public company.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
Ralph A. Hill **Age 52** **Director since 2011**	Mr. Hill was named Chief Executive Officer in April 2011. 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 face. As our Chief Executive Officer with intimate knowledge of our business and operations, Mr. Hill brings a valuable perspective to the Board. Further, we believe that Mr. Hill s experience of over 30 years with Williams is advantageous to us as a new public company.
Henry E. Lentz **Age 67** **Director since 2011**	In May 2011, Mr. Lentz retired from Lazard Frères & Co (an investment banking firm), where he had served as a Managing Director since June 2009. He was a Managing Director of Barclays Capital (an investment banking firm and successor to Lehman Brothers Inc., an investment banking firm) from September 2008 to June 2009. From January 2004 to September 2008 he was employed as an Advisory Director by Lehman Brothers. He joined Lehman Brothers in 1971 and became a Managing Director in 1976. He left the firm in 1988 to become Vice Chairman of Wasserstein Perella Group, Inc. (an investment banking firm). In 1993, he returned to Lehman Brothers as a Managing Director and served as head of the firm s worldwide energy practice. In 1996, he joined Lehman Brothers Merchant Banking Group as a Principal and in January 2003 became a consultant to the Merchant Banking Group. Mr. Lentz is currently the non-executive Chairman of Rowan Companies, Inc. and on the board of directors of Peabody Energy Corporation, Macquarie Infrastructure Company LLC and CARBO Ceramics, Inc.	We believe Mr. Lentz is well qualified to serve as a member of our Board. Mr. Lentz has significant experience in investment banking and financial matters, and we believe these experiences will be critical to his ability to identify, understand and address challenges and opportunities that we face. Mr. Lentz also has corporate governance experience as a result of serving on other public company boards of directors, which is advantageous to us as a new public company.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
George A. Lorch **Age 70** **Director since 2011**	Mr. Lorch served as a director of Williams from 2001 until December 2011, and served as a member of Williams Compensation Committee and its Nominating and Governance Committee. Mr. Lorch was 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 lead director 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 privately held 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 are critical to his ability to identify, understand and address challenges and opportunities that we face. Mr. Lorch also has knowledge and understanding of the strategy, recruitment, compensation and corporate governance issues that we face from his extensive experience as a director. Further, we believe Mr. Lorch s experience as a director of Williams is advantageous to us as a new public company.

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	Biographical Information	Experience, Qualifications and Skills for Serving on Our Board
David F. Work **Age 66** **Director since 2011**	In 2000, Mr. Work retired as Regional President from BP Amoco Corporation (a global energy company) where he served in various capacities since 1987. As Regional Vice President, Mr. Work was the senior BP Amoco representative in the Gulf Coast, Southwest and Rocky Mountain states, and his responsibilities included coordinating the vice presidents of BP Amoco s seven exploration and production business units, as well as the leaders of the gas, power, oil and chemical businesses located in the area. Prior to serving as Regional President, Mr. Work served as a Group Vice President in BP Amoco s Exploration and Production stream and was a member of its Executive Committee. Prior to the merger between BP and Amoco, Mr. Work had positions of increasing responsibility at Amoco Corporation, including Senior Vice President of Shared Services and Group Vice President of worldwide exploration for the exploration and production sector. Since 2004, Mr. Work has served on the board of directors of CGGVeritas Services Holdings Inc. (formerly Veritas DGC Inc), and since 2009, he has served on the board of directors of Cody Resources Management LLC. Mr. Work also volunteers as a member of the board of Valley Advocates for Responsible Development and the land Trust Alliance Advisory Council, is a member of the board of trustees of the Wyoming chapter of The Nature Conservancy and the Teton Science School. Mr. Work is actively involved in several professional organizations, including the American Geologic Institute and the American Association of Petroleum Geologists.	We believe Mr. Work is well qualified to serve as a member of our Board. Mr. Work has many years of experience in our industry, including operating and executive experience, and we believe these experiences are critical to his ability to identify, understand and address challenges and opportunities that we face. Mr. Work s extensive experience in identifying exploration and production opportunities are advantageous to us as a new public company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires our directors and executive officers, and certain persons who own more than ten percent of our common stock, to file with the SEC initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, executive officers and these greater than ten percent stockholders are required by SEC regulations to furnish us with copies of all Section 16(a) forms they file.

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To our knowledge, based solely on a review of the copies of these reports and other information furnished to us, all Section 16(a) filing requirements applicable to our directors, executive officers and greater than ten percent beneficial owners were complied with during and for the year ended December 31, 2011.

Board Structure

Our directors are divided into three classes serving staggered three-year terms. Class I directors have an initial term that expires in 2013; Class II directors have an initial term that expires in 2014; and Class III directors have an initial term that expires in 2015. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. The classification of our Board could have the effect of increasing the length of time necessary to change the composition of a majority of our Board. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of our Board.

Mr. Lowrie serves as the non-executive Chairman of our Board and presides at meetings of the Board as well as at meetings of the independent directors of the Board.

Audit Committee Financial Expert

Our Board has established an Audit Committee for the purpose of overseeing our accounting and financial reporting processes and audits of our financial statements, among other things. The members of the Audit Committee are Messrs. Herdman, Carrig and Lowrie. The Board has determined that Mr. Herdman has accounting or related financial management expertise and is qualified as an audit committee financial expert, and that each member of the Audit Committee is financially literate. You should understand that these designations are disclosure requirements of the SEC and the New York Stock Exchange, or NYSE, relating to the members experience and understanding of accounting and auditing matters. These designations do not affect the obligations or liability of Board or Audit Committee members generally. As described in Item 13 below, the Board has also determined that each member of the Audit Committee is independent under the SEC s and NYSE s standards applicable to Audit Committee members.

Communications with Directors

Any stockholder or other interested party may communicate with our directors, individually or as a group, by contacting our Corporate Secretary or the Chairman of the Board. The contact information is maintained on the Investor Relations page of our website at www.wpxenergy.com.

The current contact information is as follows:

WPX Energy, Inc.

One Williams Center

Tulsa, Oklahoma 74172

Attn: Chairman of the Board

WPX Energy, Inc.

One Williams Center

Tulsa, Oklahoma 74172

Attn: Corporate Secretary

Email: stephen.brilz@wpxenergy.com

Communications will be forwarded to the relevant director(s) except for solicitations or other matters not related to the Company.

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Code of Ethics

Our Board has adopted 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 for Senior Officers is publicly available on our website at wpxenergy.com. Any waiver of our Code of Ethics for Senior Officers with respect to the Chief Executive Officer, Chief Financial Officer or Controller, or persons performing similar functions, may be authorized only by our Audit Committee. In the event that we make any changes to, or provide any waivers from, the provisions of our Code of Ethics for Senior Officers, we intend to disclose such events on our website or in a report on Form 8-K with four business days of such event.

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EXECUTIVE COMPENSATION

We were spun off from Williams to form a new publicly traded entity on December 31, 2011 (the Separation Date). Prior to the spin-off, all of our named executive officers (NEO) were officers of Williams. The compensation of these officers was determined pursuant to compensation philosophy, plans, and programs put in place by Williams Compensation Committee. Our CEO, Mr. Ralph Hill, was also a NEO for Williams. Mr. James Bender, our SVP & General Counsel, was an executive officer at Williams. The Williams Compensation Committee individually approved compensation actions for both of these individuals. All other Williams officers, including WPX s remaining executive officers, had their compensation actions individually determined by the CEO and approved as group by Williams Compensation Committee.

In April, 2011, following the public announcement of the intention to create a publicly-traded exploration and production company, the Williams Compensation Committee began a process to develop the necessary compensation programs for the new company. Williams Compensation Committee engaged the services of Frederic W. Cook & Co. as its compensation consultant. Preceding the spin-off, on December 30, 2011, our Board of Directors adopted policies and plans for purposes of determining executive compensation as had been previously established by Williams Compensation Committee. In addition, our Compensation Committee engaged the services of Frederic W. Cook & Co. as its independent compensation consultant. Our Compensation Discussion and Analysis (CD&A) describes the principles and decisions underlying the executive compensation program for 2011, and necessarily includes a discussion of the compensation policies and processes of Williams Compensation Committee which our Board of Directors has since largely adopted.

Our executive team successfully led WPX Energy through the spin-off from Williams while producing strong operational and financial results. The named executive officers performance was evaluated based on the successful execution of the spin-off and on the results produced compared to annual performance goals set by Williams Compensation Committee at the beginning of 2011.

Compensation Discussion and Analysis

As our compensation programs were developed, the Williams Board of Directors and/or Compensation Committee provided input, analyzed and approved our compensation and benefit plans and policies until our Compensation Committee was formed. The compensation of our officers was determined under the Williams plans and programs through the Separation Date.

For 2012 compensation, Williams Compensation Committee approved our pay philosophy, our comparator group of companies and the 2012 compensation of our Chief Executive Officer. Our Board of Directors, on December 30, 2011, approved the 2012 compensation for other officers and perquisites and, at subsequent meetings, our Compensation Committee approved our 2012 Annual Incentive Program (AIP) and 2012 WPX Energy long-term incentive grants.

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Executive Summary

Compensation Highlights

The base salaries of our NEOs included in the Summary Compensation Table were set for 2011 by Williams Compensation Committee. These decisions were made based on the position that the executive held at Williams.

	WMB Job Title	WPX Job Title
Mr. Hill	President E&P and SVP Williams	President and Chief Executive Officer
Mr. Sailor	VP Treasurer	SVP, Chief Financial Officer and Treasurer
Mr. Bender	SVP and General Counsel	SVP and General Counsel
Mr. Guderian	VP E&P Tulsa Region	SVP of Operations
Mr. Buck	VP Commercial Ops and Gas Mgmt	SVP of Business Development and Land

On average, our NEOs received a 2.5 percent base salary increase effective March, 2011. Because of their new roles at WPX, adjustments were made to base salaries for our NEO s, except for Mr. Bender, based on a market study by the independent compensation consultant.

In February 2012, based on the Economic Value Added (EVA®[1])targets set by Williams Compensation Committee, the achievement resulted, on average, in an annual incentive award of approximately target to NEOs with respect to 2011 performance. The 2011 calculated awards were presented to our Compensation Committee which approved several increases to AIP awards for NEO s based on their leadership and work associated with the spin-off. In March 2012, our Compensation Committee approved our 2012 AIP goals.

Long-term incentive grants made in 2011 included in the Grants of Plan Based Awards table were approved by Williams Compensation Committee. Messrs. Hill and Bender received 35 percent of the grant value in performance-based restricted stock units (RSUs), 30 percent in stock options and 35 percent in time-based RSUs. Messrs. Sailor, Guderian, and Buck received 25 percent of the grant value in performance-based RSUs, 35 percent in stock options and 40 percent in time-based RSUs. Upon the spin-off, all unvested RSUs were converted from Williams RSUs to WPX Energy RSUs. RSUs with performance criteria continue to vest subject to performance measures. Vested and unvested stock options granted after December 31, 2005 were converted from Williams stock options to WPX Energy stock options. Vested stock options granted prior to December 31, 2005 were converted from Williams stock options into both adjusted Williams stock options and WPX Energy stock options based on the spin-off distribution ratio. The intent of this equity conversion process was to preserve the pre-spin-off value of equity awards. In 2012, our CEO received WPX Energy long-term incentive grants of 50 percent performance-based RSUs, 25 percent stock options and 25 percent in time-based RSUs. Our other NEOs received 35 percent of the grant value in performance-based RSUs, 25 percent in stock options and 40 percent in time-based RSUs.

Based on Williams share price performance both in absolute and relative terms to its peers, our NEOs received a 178.9 percent payout of their 2009 grant of performance-based RSUs that vested in 2012 at the end of their three-year performance period. Based on these results, our Compensation Committee ratified and approved the payout which was made in WPX Energy common shares.

Our NEOs were covered by change in control severance agreements as executives of Williams. These agreements are no longer in effect as of the spin-off. Prior to the spin-off, Williams Compensation Committee approved new change in control severance agreements for our NEOs that were effective January 1, 2012. Our Board of Directors approved these new agreements prior to the spin-off. These agreements do not provide for a gross up for any excise taxes that may be incurred by an executive if the benefits are paid.

[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co.

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Overview of Compensation Programs and Governance Practices

The main objectives of our compensation program are to pay for performance, align our named executive officers interests with those of our shareholders, and attract and retain qualified executives. We provide the following elements of compensation for our named executive officers: base salary, annual cash incentives and long-term equity-based incentives. In addition to these elements of compensation, we have established related policies and practices that ensure that executives are aligned with the interests of our shareholders as well as fairly compensated for their role and our results. These policies and practices include:

- Using the median level of the market as a starting point when setting all elements of compensation with the possibility of above or below market incentive payouts for performance results that exceed or fall short of our goals;
- Implementing our pay-for-performance philosophy with a annual incentive program that provides for cash payments based on achievement of annual financial and operational goals;
- Long-term incentives are granted 50 percent performance-based RSUs, 25 percent in time-based RSUs and 25 percent stock options for our CEO and 35 percent in performance-based RSUs, 25 percent in stock options and 40 percent in time-based RSUs for the other NEOs;
- Performance-based RSUs vest based on our relative total shareholder return compared to our peers;
- Offering no significant perquisites or other personal benefits;
- Setting stock ownership guidelines for our executive officers; and
- Adopting a policy prohibiting all employees and members of the Board from hedging our securities in any type of transaction.

Our Compensation Committee has adopted governance practices to ensure the Committee s effectiveness in fulfilling its charter. These include:

- Maintaining a committee composed solely of independent directors;
- Retaining an independent compensation consultant that performs no other consulting or services for WPX Energy; and
- Conducting an annual review and approval of our compensation policies and programs to ensure that such programs are not reasonably likely to have a material adverse effect on the Company.

Objectives of Our Compensation Programs

The objectives of the compensation programs for WPX Energy, both as a wholly-owned subsidiary of Williams and now as an independent company, are to:

- Attract and retain the talent needed to drive shareholder value;
- Help enable the Company to meet or exceed financial and operational performance targets;
- Reward employees for successfully implementing the strategy to grow the business; and
- Create long-term shareholder value.

To meet these objectives, in 2011, Williams used relative and absolute Total Shareholder Return (TSR) to measure long-term performance, and EVA® to measure annual performance. The intent for using both TSR and EVA® was to incent and pay executives to ensure that the business decisions made are aligned with the long-term interests of shareholders.

After our spin-off, our Compensation Committee adopted these objectives in its evaluation of our 2012 programs. Our 2012 programs have been established to focus our named executive officers directly on the

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success of WPX Energy as an independent exploration and production company. Our long-term performance will be measured using our TSR relative to our peers. Our annual performance will be measured considering common industry metrics including Production Volume, Production Costs, Reserve Additions and Adjusted Earnings before Interest, Taxes, Depreciation, Amortization and Exploratory Expenses (Adjusted EBITDAX).

Our Pay Philosophy

Our pay philosophy was approved by Williams Compensation Committee prior to the Separation Date. Our philosophy is to pay for performance, be competitive in the marketplace and consider the value a job provides to the Company. This philosophy was used by Williams Compensation Committee to determine our NEOs 2011 pay. The compensation programs reward NEOs and employees not just for accomplishing goals, but also for how those goals are pursued. We strive to reward the right results and the right behaviors while fostering a culture of collaboration and teamwork. Our Compensation Committee adopted this pay philosophy and continues to apply it to compensation decisions.

The principles of our pay philosophy influence the design and administration of our executives pay programs. We use 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.

WPX Energy s Pay Principles	Base pay	Annual Cash Incentives	Long-Term Incentives	Benefits
Pay should reinforce business objectives and values	ü	ü	ü	
Pay opportunity should be competitive	ü	ü	ü	ü
Incentives should align executives interest with shareholders		ü	ü	
A significant portion of an executive officer s total pay should be variable based on performance		ü	ü	
A portion of pay should be provided to compensate for core activities required for performing in the role	ü			ü
Pay should foster a culture of collaboration with shared focus and commitment to our Company		ü	ü	
Incentive pay should balance short, intermediate, and long-term performance		ü	ü	

2011 Pay Decisions

As indicated above, significant consideration was given to the need to balance the pay philosophy and practices with affordability and sustainability. Grants of long-term incentives in the form of performance-based RSUs, stock options and time-based RSUs continued in 2011 to emphasize the commitment to pay for performance.

In 2011, our named executive officers pay as established by Williams Compensation Committee were as follows:

	2011 Target Pay by NEO				
	Base Salary	Annual Incentive		Long-Term Incentive	Total
Mr. Hill	$ 507,000	65%	$ 329,550	$ 1,614,318	$ 2,450,868
Mr. Sailor	271,000	50%	135,500	344,450	750,950
Mr. Bender	488,000	65%	317,200	1,234,492	2,039,692
Mr. Guderian	308,423	50%	154,212	354,640	817,275
Mr. Buck	292,740	45%	131,733	369,162	793,635

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It is important to note that the above table and Summary Compensation Table display a value for equity awards on the date of grant. This approach does not reflect what the NEO may actually realize from their long-term incentive grants.

Williams set performance targets for its 2011 AIP during the first quarter. The 2011 EVA® performance resulted in the 2011 AIP results paying our NEOs a bonus, on average, at approximately a target payout. Included in the AIP awards, Messrs. Hill, Sailor, Bender and Buck received consideration to recognize their leadership and work associated to ensure a successful spin-off from Williams. Williams Compensation Committee approved and funded the additional awards for Messrs Hill and Bender.

2012 Pay Decisions

Williams Compensation Committee determined, prior to the Separation Date, the pay of our CEO which was effective January 1, 2012. Our Board approved the pay of our NEOs prior to the Separation Date. The pay changes were effective January 1, 2012. Each NEO s target pay by component is as follows

	2012 Target Pay by NEO				
	Base Salary	Annual Incentive		Long-Term Incentive	Total
Mr. Hill	$ 750,000	100%	$ 750,000	$ 4,000,000	$ 5,500,000
Mr. Sailor	370,000	70%	259,000	1,350,000	1,979,000
Mr. Bender	488,000	65%	317,200	1,300,000	2,105,200
Mr. Guderian	355,000	65%	230,750	1,000,000	1,585,750
Mr. Buck	345,000	65%	224,250	900,000	1,469,250

Adjustments were made to each component of compensation for our NEOs, except Mr. Bender, to reflect their new roles in an independent exploration and production company. The adjustments were made after a review by the Compensation Committee s independent compensation consultant of the compensation of executives in our comparator group of companies in our industry within an established range of revenues, assets and market capitalization. For more detail on this process, see the sections titled Our Comparator Group, Our Pay Setting Process and How the Amount for Each Type of Pay is Determined below. WPX Energy 2012 long-term incentive grants were made on February 29, 2012.

The Compensation Committee will regularly review our pay programs to ensure our ability to attract and retain the talent needed to deliver the strong financial and operating performance necessary to create shareholder value while ensuring its program effectively links pay to the performance. As part of this initial process for 2012, our Compensation Committee decided to continue awarding a significant portion of long-term incentive awards in the form of performance-based restricted stock units (RSUs). For 2012, the mix of long-term incentives granted to our NEOs is as follows:

	Mr. Hill	Other NEOs
Performance-Based RSUs	50%	35%
Stock Options	25%	25%
Time-Based RSUs	25%	40%

For 2012 awards, the metric for the performance-based RSU awards utilizes relative TSR. Williams Compensation Committee established a comparator group which is listed in Our Comparator Group for compensation purposes that will be used to measure the Company s relative performance. The performance scale that will be used determine the number of performance-based RSUs is provided under How the Amount for Each Type of Pay is Determined Long-term Incentives.

In 2012, our NEOs received additional RSUs grants with three-year cliff vesting. In recognition of their efforts in executing our successful spin-off Messrs. Hill, Sailor, Bender and Buck received additional

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discretionary RSU grants. WPX Energy does not sponsor a defined benefit plan. All applicable employees, including our NEOs, received additional RSUs based on an analysis that identified the potential difference in retirement savings due to the transition from the Williams Pension Plan and the Williams Investment Plus Plan to WPX Energy s Saving Plan (a 401(k) plan). These grants will be disclosed in next year s Grants of Plans Based Awards Table since they were granted in 2012. The values of these grants are presented in the table below.

	One-Time RSU Grants Made in 2012	
	Spin-Off Award	Retirement Analysis Award
Mr. Hill	$ 152,500	$ 297,000
Mr. Sailor	100,000	130,000
Mr. Bender	80,000	58,000
Mr. Guderian	n/a	104,000
Mr. Buck	100,000	60,000

For 2012, performance metrics to measure results for payment of our annual incentives include Production Volume, Production Costs, Reserve Additions and Adjusted EBITDAX.

Mitigating Risk

Williams Compensation Committee established our compensation philosophy and design by applying the concepts used to determine compensation for Williams NEOs. For 2011, Williams Compensation Committee conducted a thorough review and analysis and determined that the risks arising from compensation policies and practices used for the companies are not reasonably likely to have a material adverse effect. In the future, our Compensation Committee will make this assessment.

Our Compensation Recommendation and Decision Process

Role of Williams Management for 2011 and 2012 Compensation

For 2011, Williams management made recommendations for the compensation of our executives. In order to make pay recommendations, Williams management provided Williams Compensation Committee 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.

For 2012, Williams management followed the same process as above to make recommendations to William s Compensation Committee regarding the compensation of our executives with the exception that the data from annual proxy statements of companies came from our comparator group.

Role of Williams CEO

For 2011, before recommending base pay adjustments and long-term incentive awards to the Williams Compensation Committee, Williams CEO reviewed the competitive market information related to our executives while also considering internal equity and individual performance. For 2012, Williams CEO reviewed the competitive market information related to our CEO considering the spin-off of WPX Energy and what was competitive for the CEO of WPX Energy as the leader of an independent company.

Role of Williams Compensation Committee

Williams Compensation Committee reviewed the Williams CEO s recommendations, supporting market data and individual performance assessments for our CEO and other NEOs prior to the Separation Date. In addition, Williams Compensation 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.

Williams Compensation Committee and Board of Directors approved the pay recommendations for our CEO for 2011 as a named executive officer and business unit leader of Williams. Prior to the Separation Date, our Board of Directors approved the pay recommendations for our CEO and the other NEOs for 2012.

For the 2011 annual cash incentive program, the Williams Compensation Committee approved the EVA® attainment which was provided to us.

Role of WPX Energy Management for Compensation

In the future, our management will follow a similar process as Williams management and make recommendations for the compensation of our executives to our Compensation Committee. In order to make pay recommendations, WPX Energy management will provide our Compensation Committee with data from the annual proxy statements of companies in our comparator group along with pay information compiled from nationally recognized executive and industry related compensation surveys. The survey data will be used to confirm that pay practices among companies in the comparator group are aligned with the market as a whole.

Role of WPX Energy s CEO

For the 2011 annual cash incentive program, our CEO used the EVA® attainment ratified by the Williams Compensation Committee as the basis for his recommended payouts to our NEOs, other than himself. Our CEO s recommendation includes an assessment of each NEO s individual performance for 2011 based on achievement of business goals, their contribution to the spin-off, and demonstrated key leadership competencies (for more on leadership competencies, see the section entitled Base Pay in this Compensation Discussion and Analysis).

In the future, our CEO, before recommending base pay adjustments and long-term incentive awards to our Compensation Committee for our NEOs other than himself, will review the competitive market information while also considering internal equity and individual performance.

For the 2012 annual cash incentive program, our CEO s recommendation is to measure results based on the attainment of Production Volume, Production Costs, Reserve Additions and Adjusted EBITDAX with a potential adjustment for individual performance.

Role of the Other NEOs

The other NEOs of Williams and WPX Energy have no role in setting compensation for any of our NEOs.

Role of WPX Energy s Board of Directors and Compensation Committee

For the 2011 annual cash incentive program, our Compensation Committee received the NEO awards approved by the Williams Compensation Committee based on EVA® attainment. Payouts were approved by our Compensation Committee based on these results and recommended by our CEO for the NEOs other than himself. His recommendations included each NEO s contribution to the spin-off, if applicable.

For 2012, our Board of Directors approved the compensation of our NEOs prior to the Separation Date. In the future, for all of our NEOs, except the CEO, our Compensation Committee will review our CEO s recommendations, supporting market data and individual performance assessments. In addition, our Compensation Committee will consult with their independent compensation consultant to review all of the data and advises on the reasonableness of our CEO s pay recommendations.

The process for determining the CEO s compensation in future years will be determined by our Compensation Committee.

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The new process and competitive market information provided by its independent compensation consultant will be used to determine our CEO s long-term incentive amounts, annual cash incentive target, base pay and any performance adjustments to be made to our CEO s annual cash incentive payment.

Role of the Independent Compensation Consultant

For 2011 and 2012, Frederic W. Cook & Co., Inc. provided assistance in determining the compensation for our executive officers. Frederick W. Cook & Co., Inc. served as the independent compensation consultant, provided input and analysis as Williams Compensation Committee approved our compensation and benefit plans and policies until our Compensation Committee was formed.

In the future, our independent compensation consultant will present competitive market data that includes proxy data from the approved comparator group and published compensation data, using the same surveys and methodology used for the other NEOs (described in the Role of WPX Energy Management for Compensation section in this Compensation Discussion and Analysis). Our comparator group will be developed by the Committee s independent compensation consultant, with input from management, and approved by the Compensation Committee.

Our Comparator Group

How WPX Energy Uses its Comparator Group

We refer to publicly available data showing our comparator group s pay levels and forms or pay. This allows the Compensation Committee to ensure competitiveness and appropriateness of proposed compensation packages. When setting pay, the Compensation Committee uses market median information of our comparator group as a reference point. Actual pay may exceed market median if warranted by superior performance, and fall below market median for underperformance.

Composition of WPX Energy s Comparator Group

Williams established our initial comparator group prior to the Separation Date. Each year the Compensation Committee will review the comparator group to ensure that it is still appropriate. Our comparator group focuses on companies that work in the same industry segment and reflect where we compete for business and talent. The 2012 comparator group included 16 companies which are in the chart below.

Characteristics of WPX Energy s Comparator Group

Companies in our 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, we take a broader view of comparability to include organizations that are similar to us in some, but not all, respects. This results in compensation that is appropriately scaled and reflects comparable complexities in business operations.

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Composition of Our Comparator Group

Our comparator group approved prior to the Separation Date by the Williams Compensation Committee is provided below. This group, with the exception of Petrohawk Energy Corporation which was acquired in 2011, will be used in making our compensation decisions. It is also used to measure our relative TSR performance for our performance-based RSUs granted in 2012 as described in the section How the Amount for Each Type of Pay is Determined 2012 Performance-Based RSUs.

Cabot Oil & Gas Corp.	Pioneer Natural Resources Co.
Chesapeake Energy Corp.	QEP Resources Inc.
Cimarex Energy Corp.	Petrohawk Energy Corporation
Devon Energy Corp.	Range Resources Corp.
EOG Resources Inc.	Sandridge Energy Inc.
Forest Oil Corp.	SM Energy Co.
Newfield Exploration Co.	Southwestern Energy Co.
Noble Energy Inc.	Ultra Petroleum Corp.

Our Pay Setting Process

Setting pay for our NEOs will be an annual process that occurs during the first quarter of the year. The Compensation Committee completes a review to ensure that pay is competitive, equitable and encourages and rewards performance.

The compensation data of our comparator group as disclosed in proxy statements is the primary market data, if available, 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) may be used to supplement and validate our comparator group market data for these executive officers.

Although the Compensation 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 the Company, internal pay equity is also considered when making pay decisions. Other considerations when making future pay decisions for the NEOs will include historical pay and tally sheets that include annual pay and benefit amounts, wealth accumulated and the total aggregate value of the NEOs equity awards and holdings.

For 2012, Williams Compensation Committee reviewed the compensation data for us prior to the Separation Date. In the future, our Compensation Committee will undertake this entire process for our NEOs.

When setting pay, we determine a target pay mix (distribution of pay among long-term incentives, annual incentives and base pay) for the NEOs. Consistent with our pay-for-performance philosophy, the actual amounts paid are determined based on our Company s performance and individual performance. The following table provides the 2011 target pay mix by NEO.

	2011 Target Pay Mix by NEO			
	Base Salary	**Annual Incentive**	**Long-Term Incentive**	**Total**
Mr. Hill	21%	13%	66%	100%
Mr. Sailor	36%	18%	46%	100%
Mr. Bender	24%	16%	60%	100%
Mr. Guderian	38%	19%	43%	100%
Mr. Buck	37%	17%	46%	100%

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The majority of 2012 target pay is variable with the largest component of the mix delivered through long-term incentive, aligning the NEOs pay with shareholder interests. The following table provides the 2012 target pay mix by NEO.

	2012 Target Pay Mix by NEO			
	Base Salary	Annual Incentive	Long-Term Incentive	Total
Mr. Hill	14%	14%	72%	100%
Mr. Sailor	19%	13%	68%	100%
Mr. Bender	23%	15%	62%	100%
Mr. Guderian	22%	15%	63%	100%
Mr. Buck	24%	15%	61%	100%

How the Amount for Each Type of Pay is Determined

Long-term incentives, annual cash incentives, base pay and benefits accomplish different objectives.

Long-Term Incentives

WPX Energy awards long-term incentives to reward performance and align NEOs with long-term shareholder interests by providing NEOs with an ownership stake in the Company, 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, we consider the following factors:

- the proportion of long-term incentives relative to base pay;
- the NEO s impact on our performance and ability to create value;
- long-term business objectives;
- awards made to NEOs in similar positions within our 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 WPX Energy;
- the NEO s demonstrated performance over the past few years; and
- the NEO s leadership performance.

The allocation of the 2012 long-term incentive program for our NEOs averages about 65 percent of total compensation. The CEO s 2012 long-term incentive allocation is greater than the other NEOs at 72 percent, which creates a strong shareholder alignment. The CEO s long-term incentives are granted 50 percent in performance-based RSUs, 25 percent in time-based RSUs and 25 percent in stock options. The other NEOs long-term incentives are granted 35 percent in performance-based RSUs, 25 percent in stock options and 40 percent in time-based RSUs.

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	**Shareholder alignment**	**Stock ownership**	**Drives operating and financial performance**	**Retention Incentive**
Performance-Based RSUs				
Relative TSR	l	l	l	
Stock Options				
Stock Price Appreciation	l			
Time-Based RSUs				
Stock Price Appreciation		l		l

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2011 Performance-Based RSUs

Shown in the chart below are the absolute and relative TSR targets used by Williams for the performance-based restricted stock unit awards for the 2011 to 2013 performance period and the continuum that will determine the resulting potential payout level:

Williams Relative TSR

100th %ile	60%	100%	125%	150%	175%	200%
75th%ile	30%	75%	100%	125%	150%	175%
50th%ile	0%	50%	75%	100%	125%	150%
25th%ile	0%	25%	50%	75%	100%	125%
<25th%ile	0%	0%	0%	30%	60%	100%
	<7.5%	7.5%	10.0%	12.5%	15.0%	18.0%
		Threshold		Target		Stretch

Williams Annualized Absolute TSR

2012 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 our long-term shareholders.

We believe it is important to measure TSR on a relative basis. Additionally, we believe awards should be influenced by how TSR compares to the TSR of companies in our comparator group. Regardless of our relative TSR performance to peers at the end of the performance period, payouts are capped at 100% in any performance cycle in which the absolute TSR of the Company is negative. Shown in the chart below are relative TSR targets for the performance-based restricted stock unit awards for the three year performance period, 2012 to 2014:

TSR	**Shares Earned as % of Target Grant**
75th percentile or higher	200%
50th percentile	100%
25th percentile	30%
Below the 25th percentile	0%

If the resulting TSR ranking is between these goals, the percentage of shares earned will be interpolated.

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. Stock options have a ten year term and vest in equal increments over three years from the grant date.

Time-Based RSUs

This type of equity is used to retain executives and to facilitate stock ownership. Time-based RSUs have a three year cliff vesting schedule. The use of time-based RSUs is also consistent with the practices of the comparator group of companies.

Grant Practices

The Compensation Committee will approve 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.

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The grant date for off-cycle grants for individuals, 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, WPX removes grant timing from the influence of the release of material information.

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 us an idea of what other companies target to pay in annual cash incentives for similar jobs. We also consider the internal value of each job i.e., how important the job is to executing its strategy compared to other jobs in the Company before the target is set for the year. The 2011 and 2012 annual cash incentive targets as a percentage of base pay for the NEOs are as follows:

	2011 Target	2012 Target
Mr. Hill	65%	100%
Mr. Sailor	50%	70%
Mr. Bender	65%	65%
Mr. Guderian	50%	65%
Mr. Buck	45%	65%

The 2011 Target for Mr. Hill and the other NEOs reflect their responsibility with Williams. The 2012 targets are based on their new leadership positions for WPX Energy.

2011 Annual Cash Incentives

Williams provided 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. Our NEOs participated in the program through the Separation Date. Simply stated, it is the financial return in a given period less the capital charge for that period. The calculation used is as follows:

		Adjusted Net Operating		Adjusted Capital Charge (the amount
EVA®	=	Profits after Taxes	<u>*Less*</u>	of capital invested
		(NOPAT)		multiplied by the cost of capital)

EVA® is first calculated as NOPAT less Capital Charge. Williams incentive program allowed for the Compensation 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 shareholders and to ensure executives were not rewarded for positive results they did not facilitate nor are they penalized for certain unusual circumstances outside their control.

For 2011, Williams provided the calculated incentive awards based on the EVA® results. We used these calculations for our NEOs 2011 awards since WPX Energy was a wholly-owned subsidiary of Williams until the Separation Date.

2011 Annual Cash Incentives Actual

For NEOs, the annual cash incentive program was funded when Williams attained 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 shareholder value. To determine the funding of the annual cash incentive, Williams used the following calculation for each NEO:

Actual Base Pay received in 2011	X	Incentive Target %	X	EVA® Goal Attainment %

Actual payments may be adjusted upward to recognize individual performance that exceeded expectations, such as success toward business unit and individual goals and successful demonstration of the leadership

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competencies. Payments may also be adjusted downwards if performance warrants. For 2011 payouts, Williams provided calculated awards based on the EVA® attainment to us and any adjustments to recognize individual performance were recommended by our CEO. Actual payouts to our NEOs based on our CEO s recommendations were approved by our Compensation Committee.

How Williams Set the 2011 EVA® Goals

Setting the EVA® goals for the annual cash incentive program began 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 CEO, chief financial officer and other NEOs.

Using the plan guidance, Williams management establishes the EVA® goal and recommends it to Williams Compensation Committee.

Williams Compensation Committee reviews, discusses and makes adjustments as necessary to management s recommendations and sets the goal at the beginning of each year.

Thereafter, progress toward the goal is regularly monitored and reported to Williams Compensation Committee throughout the year. Based on EVA® performance relative to the established goals, Williams Compensation Committee certified the 2011 EVA® performance results and approved payment of the annual cash incentive plan, which were provided to our Compensation Committee. Our Compensation Committee used this information and approved additional cash awards for select NEOs for their leadership and contribution to the spin-off.

2012 Annual Cash Incentives

WPX Energy will provide annual cash incentives to encourage and reward NEOs for making decisions that improve our performance using new metrics that we believe better measure performance as an independent exploration and production company. For 2012, the Compensation Committee will consider the following performance metrics in determining our annual incentives:

2012 Annual Incentive Metric	Definition of the Metric	Weighting
Production Volume	Volumes as reported publically in financial results based on sales of oil, gas, and natural gas liquids	30%
Production Costs	Sum of Lease Operating Expenses, Facility Operating Expenses, and Selling, General, and Administrative Expenses Divided by Production Volume for $/Mcfe	30%
Reserve Additions	Year end proved reserves additions as defined by the SEC and as reported in Supplemental Oil and Gas Disclosures from 10K	20%
Adjusted EBITDAX	Earnings before Interest, Taxes, Depreciation, Amortization and Exploratory Expenses	20%

When developing the metrics, we used the following principles to ensure the program drives the intended behaviors.

Drive a culture that recognizes and rewards enterprise growth and cost management

Ensure transparency and alignment to shareholders

Ensure employees ability to track progress and directly link performance to results

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Have all employees driving for the same goals

Balance focus of growth, cost management and profitability

Recognize and reward individual performance

Keep it simple

When setting the goals for the annual incentive program, we began with our rigorous internal budgeting and planning which includes an evaluation of the challenges and opportunities for the business.

Management will regularly review with the Compensation Committee a supplemental scorecard reflecting the Company s production volume components, capital efficiency, capital expenditures, and leading indicators safety measures. The supplemental scorecard provides reliable updates regarding the Company s performance as well as ensures alignment between these measures and the performance metric identified above. This supplemental scorecard provides the Compensation Committee with additional performance data to assist in determining final AIP awards.

Base Pay

Base pay compensates NEOs for carrying out the duties of their jobs and serves as the foundation of our 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 our 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 our business objectives and goals, business strategies, and personal development plans. Right Way reflects the NEOs behavior as exhibited through our leadership competencies. Competencies focus on how results are achieved and provide clarity on expectations. Williams grouped their competencies into four core leadership areas: Foundational, Organizational, Operational, and People. WPX Energy s management will adopt new competencies in 2012.

Benefits

Consistent with our philosophy to emphasize pay for performance, NEOs receive very few perquisites (perks) or supplemental benefits. They are as follows:

Financial Planning Reimbursement. We reimburse for 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 our compensation programs which we believe maximizes the retention and engagement aspects of the dollars we spend on these programs.

Personal Use of WPX Energy s Company Aircraft. We provide limited personal use of Company aircraft at the CEO s discretion. Our policy for all executive officers is to discourage personal use of the aircraft, but the CEO retains discretion to permit its use when he deems appropriate, such as when the destination is not well served by commercial airlines or personal emergencies.

Executive Physicals. Executive officer physicals align with our wellness initiative as well as assist us in mitigating risk. These physicals reduce vacancy succession risk because they help to identify and prevent issues that would leave a role vacated unexpectedly.

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Additional Components of WPX Energy s Executive Compensation Program

In addition to establishing the pay elements described above, we have a number of policies to further the goals of the executive compensation program, particularly with respect to strengthening the alignment of NEOs interests with shareholder long-term interests.

Recoupment Policy

We maintain a recoupment policy to allow recovery of incentive-based compensation from executive officers in the event we are 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

To help ensure shareholder alignment, all NEOs must hold an equity interest in WPX Energy. The chart below shows the NEO stock ownership guidelines.

Position	Holding Requirement as a multiple of Base Pay
CEO	6
Other NEOs	3

The Compensation Committee will review the guidelines annually for competitiveness and alignment with best practice and monitors the NEOs progress toward compliance. Shares owned outright, including beneficial shares owned and unvested time-based RSUs are counted toward the guideline. An NEO below the holding requirement as a multiple of base pay must retain 50 percent of any equity of the Company acquired through the exercise of stock options or the vesting of time-based or performance-based RSUs, net of taxes, until the NEO s WPX stock ownership is at or above the holding requirement. The Compensation 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

Our 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, we prohibit officers, directors and certain key employees from entering into short sales or use of equivalent derivative securities.

Accounting and Tax Treatment

We will consider the impact of accounting and tax treatment when designing all aspects of pay, but the primary driver of our program design is to support our business objectives. The tax deductibility guidelines under Internal Revenue Code Section 162(m) for performance-based compensation to executive officers is a key consideration in our overall plan design, however we maintain the flexibility to provide compensation that supports our business objectives.

Employment Agreements

We do not enter into employment agreements with the NEOs and can remove a 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 Compensation 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 Compensation Committee takes into consideration the NEO s term of employment, past accomplishments, reasons for separation from the Company 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.

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Rationale for Change in Control Agreements

While Williams employees, our NEOs were covered by change in control agreements with Williams. These agreements are no longer in effect as of the Separation Date. Prior to the spin-off, Williams Compensation Committee approved our change in control agreements effective January 1, 2012. Our Board of Directors approved these new agreements prior to the spin-off. Like Williams agreements, our change in control agreements, in conjunction with the NEOs RSU agreements, provide separation benefits for the NEOs. Our program includes a double trigger for benefits and equity vesting. This means there must be a change in control 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 our comparator group, this practice creates security for the NEOs, but does not provide an incentive for NEOs to leave immediately after a change in control. Our agreements do not contain an excise tax gross-up provision, but instead 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. The program is designed to encourage the NEOs to focus on the best interests of our shareholders by alleviating their concerns about a possible detrimental impact to their compensation and benefits under a potential change in control, not to provide compensation advantages to NEOs for executing a transaction.

The Compensation Committee will review our change in control benefits periodically to ensure they are consistent with competitive practice and aligned with our compensation philosophy. As part of the review, calculations will be performed to determine the overall program costs 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. Our Compensation Committee believes that offering a change in control program is appropriate and critical to attracting and retaining executive talent and keeping them aligned with our shareholder interests in the event of a change in control.

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 the Company, shareholders and the NEO. Please also see the Change in Control Agreements section below for further discussion of our change in control program.

Change in Control Benefit	**What does the benefit provide to the Company and shareholders?**	**What does the benefit provide to the NEO?**
Multiple of 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 two years of continued employment. (Three years for our CEO.)
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 the Company that creates a competitive benefit.	Access to health coverage.
Reimbursement of legal fees to enforce benefit	Keeps NEOs focused on the Company 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.

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Treatment of Outstanding Williams Long-Term Incentive Awards upon the Spin-off

In anticipation of our spin-off, Williams Compensation Committee approved the adjustments to be made upon successful completion of the spin-off. As of the Separation Date, all unvested, outstanding Williams long-term incentives awards were converted to WPX Energy awards. The new WPX Energy awards are the same type of award with the same terms and provisions as prior to the Separation Date, but are governed by the 2011 WPX Energy Incentive Plan. Vested and unvested stock options granted after December 31, 2005 were converted from Williams stock options to WPX Energy stock options. Vested stock options granted prior to December 31, 2005 were converted from Williams stock options into both adjusted Williams stock options and WPX Energy stock options based on the spin-off distribution ratio. All adjustments were made equitably, preserving the intrinsic value, based on the value of Williams volume weighted average stock price before the spin-off (Pre-Spin WMB Stock Price) and both Williams and WPX Energy s volume weighted average stock price after the spin-off (Post-Spin WMB Stock Price and Post-Spin WPX Energy Stock Price, respectively). The volume weighted average stock price, a common trading benchmark especially for pension plans, is calculated by adding up the dollars traded for every transaction (price multiplied by number of shares traded) and then dividing by the total shares traded for the day.

Unvested Performance-Based and Time-Based RSUs

WPX Energy employees holding unvested Williams RSUs received unvested WPX Energy RSUs of similar value. The Williams RSUs were cancelled.

Number of Unvested Williams RSUs	x	Pre-Spin WMB Stock Price	/	Post-Spin WPX Energy Stock Price	=	Number of Unvested WPX Energy RSUs

Below is an example of this conversion for a February 23, 2010 grant of 1,000 unvested Williams RSUs to unvested WPX Energy RSUs.

	Prior to Spin-off	**After Spin-off**
Number of RSUs	1,000 Unvested Williams RSUs	1,806 Unvested WPX Energy RSUs
Stock Price	Pre-Spin WMB Stock Price	Post-Spin WPX Energy Stock Price
Vesting	3 year cliff, February 23, 2013	3 year cliff, February 23, 2013

The measurement of the existing performance-based RSUs granted in 2010 and 2011 will be based on the total shareholder return of WMB and WPX stocks relative to the originally established comparator group. The value of the WPX stock included in the total shareholder return calculation will be adjusted using the spin-off distribution ratio.

All Unvested Stock Options and Vested Stock Options Granted After 2005

WPX Energy employees holding unvested Williams stock options received unvested WPX Energy stock options of similar value. The original Williams stock options were cancelled. The number of WPX Energy stock options is determined as follows:

Number of Unvested Williams Stock Options	X	(Pre-Spin WMB Stock Price	/	Post-Spin WPX Energy Stock Price)	=	Number of Unvested WPX Energy Stock Options

The resulting strike price of WPX Energy stock options is determined as follows:

Original Strike Price of Williams Stock Options	x	(Post-Spin WPX Stock Price	/	Pre-Spin WMB Stock Price)	=	Resulting Strike Price of WPX Energy Stock Options

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Below is an example of this conversion for a February 23, 2010 grant of 1,000 unvested Williams stock options to unvested WPX Energy stock options.

	Prior to Spin-off	After Spin-off
Number of Stock Options	1,000 Unvested Williams Stock Option	1,806 Unvested WPX Energy Stock Options
Strike Price	$21.22 Original Williams Strike Price	$11.75 WPX Energy Strike Price
Stock Price	Pre-Spin WMB Stock Price	Post-Spin WPX Energy Stock Price
Vesting	One-third vests each year for three years	One-third vests each year for three years
Expiration Date	February 23, 2020	February 23, 2020

Vested Stock Options Granted Prior to 2006

WPX Energy employees, who at the Separation Date, held vested Williams stock options granted prior to 2006 received an allocation of both vested adjusted Williams stock options and vested WPX Energy stock options. The allocation of the new awards considered the distribution ratio of one WPX Energy share that was distributed to Williams shareholders for every three shares of Williams stock held. All adjustments were made equitably, preserving the intrinsic value, based on the value of the Pre-Spin WMB Stock Price and the values of the Post-Spin WMB Stock Price and the Post-Spin WPX Energy Stock Price.

The resulting strike price of the Williams stock options is determined as follows:

Original Strike Price of Williams Stock Options	x	(Post-Spin WMB Stock Price	/	Pre-Spin WMB Stock Price)	=	Resulting Strike Price of Williams Stock Options

The resulting strike price of WPX Energy stock options is determined as follows:

Original Strike Price of Williams Stock Options	x	(Post-Spin WPX Stock Price	/	Pre-Spin WMB Stock Price)	=	Resulting Strike Price of WPX Energy Stock Options

The adjusted number of Williams stock options is determined as follows:

Number of vested Williams Stock Options	x	Pre-Spin WMB Stock Price	/	Aggregate Post-Spin Value

The adjusted number of WPX Energy stock options is determined by using the same equation as above and multiplying the result by the spin-off distribution ratio of WPX Energy shares to Williams shares.

Below is an example of this conversion for a February 23, 2005 grant of 1,000 vested Williams stock options to vested both Williams and WPX Energy stock options.

		After Spin-off	
	Prior to Spin-off	Williams	WPX Energy
# of Stock Options	1,000 Vested Williams Stock Option granted prior to 2006	1,000 Vested Williams Stock Options	333 Vested WPX Energy Stock Options
Strike Price	$21.22 Original Williams Strike Price	$17.28 Adjusted Williams Strike Price	$11.75 WPX Energy Strike Price
Stock Price	Pre-Spin WMB Stock Price	Post-Spin WPX Energy Stock Price	Post-Spin WPX Energy Stock Price

Vesting	Previously vested	Previously vested
Expiration Date	February 23, 2015	February 23, 2015

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Executive Compensation and Other Information

2011 Summary Compensation Table

The following table sets forth certain information with respect to the compensation of the NEOs earned during fiscal years 2011, 2010, and 2009.

Name and Principal Position(1)	Year	Salary(2)	Bonus(3)	Stock Awards(4)	Option Awards(5)	Non-Equity Incentive Plan Compensation(6)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(7)	All Other Compensation(8)	Total
Ralph A. Hill	2011	$ 505,108	$	$ 1,304,947	$ 309,371	$ 538,979	$ 765,938	$ 33,743	$ 3,458,086
President &	2010	493,208		1,257,287	356,777	384,479	315,626	16,304	2,823,681
Chief Executive Officer	2009	503,654		1,056,319	525,969	566,473	427,867	37,786	3,118,068
Donald R. Chappel	2011	627,231		1,611,982	382,162	755,051	486,435	18,484	3,881,345
Former Senior Vice	2010	610,154		1,436,882	407,743	559,052	225,539	16,320	3,255,690
President, Chief Financial	2009	623,077		1,242,734	618,783	765,047	383,380	16,320	3,649,341
Officer and Treasurer									
Rodney J. Sailor Senior Vice President, Chief Financial Officer and Treasurer	2011	257,448	100,000	264,736	79,714	142,253	260,751	13,832	1,118,734
James J. Bender	2011	486,677		997,911	236,581	449,132	398,852	34,305	2,603,458
Senior Vice President and	2010	477,954		933,975	265,033	359,122	188,427	33,900	2,258,411
General Counsel	2009	488,077		807,773	402,209	522,119	250,679	26,647	2,497,504
Bryan K. Guderian Senior Vice President of Operations	2011	273,096		272,567	82,073	155,329	308,316	15,492	1,106,873
Neal A. Buck Senior Vice President of Business Development and Land	2011	265,347	100,000	283,728	85,435	138,074	224,660	15,452	1,112,696

(1) **Name and Principal Position.** As of December 31, 2011, Mr. Chappel no longer served as our Chief Financial Officer.

(2) **Salary.** Actual salary paid may differ from the annual rate due to the number of pay periods during the year.

(3) **Bonus.** Awards were made to Messrs. Sailor and Buck for the efforts to ensure a successful spin-off from Williams.

(4) **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 William s Annual Report on Form 10-K for the year-ended December 31, 2011.

The potential maximum values of the performance-based RSUs, subject to changes in performance outcomes, are as follows:

	2011 Performance-Based RSU Maximum potential
Ralph A. Hill	$ 1,414,253
Donald R. Chappel	1,747,008
Rodney J. Sailor	225,047
James J. Bender	1,081,499
Bryan K. Guderian	231,685
Neal A. Buck	241,186

(5) **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 with FASB ASC Topic 718. The assumptions used to value the option awards can be found in Williams Annual Report on Form 10-K for the year-ended December 31, 2011.

(6) **Non-Equity Incentive Plan**. Under Williams AIP, the maximum annual incentive pool funding for NEOs is 250 percent of target and the incentive reserve, into which certain awards were required to be deferred, was eliminated, beginning in 2009. Any existing reserve balances for the NEOs continued to be at risk and were paid after meeting the threshold performance targets. In 2009, 2010 and 2011 a portion of the respective reserve balance was paid to each NEO each year. After 2011 AIP awards no reserve balances remained.

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The reserve amounts paid in 2012 as it relates to 2011 performance are as follows:

	Reserve Balance
Ralph A. Hill	$ 36,479
Donald R. Chappel	30,052
James J. Bender	22,132

(7) **Change in Pension Value and Nonqualified Deferred Compensation Earnings.** The amount shown is the aggregate change from December 31, 2010 to December 31, 2011 in the actuarial present value of the accrued benefit under the qualified pension and supplemental plan sponsored by Williams. WPX Energy does not sponsor a qualified pension and supplemental plan.

(8) **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 and personal use of the 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 our NEOs in the aggregate amounts do not exceed $25,000 for Mr. Hill and Mr. Bender. Mr. Bender did exceed $10,000 for financial planning, incurring $15,000 in 2011.

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2011 Grants of 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 2011 to the NEOs. All information is presented as of the grant date and is not adjusted for the spin-off.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards			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	Grant Date Fair Value of Stock and Option Awards
Name	**Grant Date**	**Threshold**	**Target**	**Maximum**	**Threshold**	**Target(2)**	**Maximum**				
Ralph A. Hill	2/24/2011	$ 36,479	364,799	857,280					40,126	29.73	309,371
	2/24/2011					21,731	43,462				707,127
	2/24/2011							21,731			597,820
Donald R. Chappel	2/24/2011	30,051	500,475	1,206,110					49,567	29.73	382,162
	2/24/2011					26,844	53,688				873,504
	2/24/2011							26,844			738,478
Rodney J. Sailor	2/24/2011		135,000	337,500				5,533			152,213
	2/24/2011					3,458	6,916				112,523
	2/24/2011								10,339	29.73	79,714
James J. Bender	2/24/2011	22,132	339,322	848,305							457,161
	2/24/2011					16,618	33,236			29.73	540,750
	2/24/2011								16,618		236,581
Bryan K. Guderian	2/24/2011		154,212	385,529				5,697			156,724
	2/24/2011					3,560	7,120				115,842
	2/24/2011								10,645	29.73	82,073
Neal A. Buck	2/24/2011		131,733	329,333				5,930			163,134
	2/24/2011					3,706	7,412			29.73	120,593
	2/24/2011								11,081	29.73	85,435

(1) Non-Equity Incentive Awards. Awards from Williams 2011 AIP are shown.

Threshold: At threshold, the 2011 AIP awards would be zero. Because the AIP reserve balance from prior years was payable in 2012 upon meeting threshold performance, the reserve balance is shown for Mr. Hill, Mr. Chappel and Mr. Bender.

Target: The amount shown is based upon an EVA® attainment of 100%, plus the AIP reserve balance for Mr. Hill, Mr. Chappel and Mr. Bender.

Maximum: The maximum amount the NEOs can receive is 250% of their AIP target, plus the AIP reserve balance for Mr. Hill, Mr. Chappel and Mr. Bender.

(2) Represents performance-based RSUs granted under William s 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 threshold goals are not met, the NEO s awards are cancelled in their entirety. With the conversion at the spin-off of these unvested Performance-based RSUs to WPX Energy Performance-based RSUs, the vesting provisions remain the same.

(3) Represents time-based RSUs granted under William s 2007 Incentive Plan. Time-based units vest three years from the grant date of 2/24/2011 on 2/24/2014. With the conversion at the spin-off of these unvested RSUs to WPX Energy RSUs, the vesting provisions remain the same.

(4) Represents stock options granted under William s 2007 Incentive Plan. Stock options granted in 2011 become exercisable in three equal annual installments beginning one year after the grant date. One-third of the options vested on 2/243/2012. Another one-third will vest on 2/24/2013, with the final one-third vesting on 2/24/2014. Once vested, stock options are exercisable for a period of 10 years from the grant date. With the conversion at the spin-off of these unvested options to WPX Energy options, the vesting provisions remain the same.

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2011 Outstanding 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 2011. All information presented is not adjusted for the spin-off. Please see Supplemental Disclosure of Post-Spin-off Outstanding Equity Awards table below which present the awards as adjusted for the spin-off.

	Option Award						Stock Awards				
Name	**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 (2)**	**Market Value of Shares or Units of Stock That Have Not Vested(4)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units of Stock or Other Rights That Have Not Vested (3)**	**Equity Incentive Plan Award: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested(4)**
Ralph A. Hill	2/24/2011		40,126		29.73	2/24/2021	2/24/2011	21,731	717,558	21,731	717,558
	2/23/2010	16,941	33,882		21.22	2/23/2020	2/23/2010	30,733	1,014,804	30,733	1,014,804
	2/23/2009	62,615	31,308		10.86	2/23/2019	2/23/2009	62,173	2,052,952	62,173	2,052,952
	2/25/2008	38,587			36.50	2/25/2018					
	2/26/2007	43,605			28.30	2/26/2017					
Donald R. Chappel	2/24/2011		49,567		29.73	2/24/2021	2/24/2011	26,844	886,389	28,844	886,389
	2/23/2010	19,361	38,722		21.22	2/23/2020	2/23/2010	35,123	1,159,761	35,123	1,159,761
	2/23/2009	73,664	36,833		10.86	2/23/2019	2/23/2009	73,145	2,415,248	73,145	2,415,248
	2/25/2008	50,772			36.50	2/25/2018					
	2/26/2007	48,450			28.30	2/26/2017					
	3/3/2006	41,921			21.67	3/3/2016					
	2/25/2005	55,000			19.29	2/25/2015					
	2/5/2004	75,000			9.93	2/5/2014					
	4/16/2003	175,000			5.10	4/16/2013					
Rodney A. Sailor	2/24/2011		10,339		29.73	2/24/2021	2/24/2011	3,458	114,183	5,533	182,700
	2/23/2010	3,866	7,734		21.22	2/23/2020	2/23/2010	4,291	141,689	6,866	226,715
	2/23/2009	11,342	5,672		10.86	2/23/2019	2/23/2009	6,684	220,706	10,695	353,149
	2/25/2008	9,139			36.50	2/25/2018					
	2/26/2007	9,448			28.30	2/26/2017					
	3/3/2006	8,537			21.67	3/3/2016					
	7/19/2005	4,000			20.44	7/19/2015					
	2/25/2005	12,000			19.29	2/25/2015					
James J. Bender	2/24/2011		30,685		29.73	2/24/2021	2/24/2011	16,618	548,726	16,618	548,726
	2/23/2010	12,584	25,170		21.22	2/23/2020	2/23/2010	22,830	753,847	22,830	753,847
	2/23/2009	47,882	23,941		10.86	2/23/2019	2/23/2009	47,544	1,569,903	47,544	1,569,903
	2/25/2008	30,463			36.50	2/25/2018					
	2/26/2007	29,070			28.30	2/26/2017					
	3/3/2006	24,136			21.67	3/3/2016					
Bryan K. Guderian	2/24/2011		10,645		29.73	2/24/2021	2/24/2011	3,560	117,551	5,697	188,115
	2/23/2010	4,419	8,839		21.22	2/23/2020	2/23/2010	4,904	161,930	7,847	259,108
	2/23/2009	2,160	4,321		10.86	2/23/2019	2/23/2009	7,639	252,240	12,223	403,603
	2/25/2008	11,862			36.50	2/25/2018					
	2/26/2007	14,535			28.30	2/26/2017					

Neal A Buck	2/24/2011		11,081	29.73	2/24/2021	2/24/2011	3,706	122,372	5,930	195,809
	2/23/2010	4,419	8,839	21.22	2/23/2020	2/23/2010	4,904	161,930	7,847	259,108
	2/23/2009	7,962	6,482	10.86	2/23/2019	2/23/2009	7,639	252,240	12,223	403,603
	2/25/2008	10,236		36.50	2/25/2018					
	2/26/2007	14,535		28.30	2/26/2017					
	3/3/2006	11,433		21.67	3/3/2016					
	2/25/2005	15,000		19.29	2/25/2015					

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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 30, 2011.

Grant Date	Vesting Schedule	Vesting Dates
2/24/2011	One-third vests each year for three years	2/24/2012, 2/24/2013, 2/24/2014
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

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
2/24/2011	100% vests in three years	2/24/2014
2/23/2010	100% vests in three years	2/23/2013
2/23/2009	100% vests in three years	2/23/2012

(3) All performance-based RSUs are subject to attainment of performance targets established by the Compensation Committee. These awards will vest no earlier than the end of the performance period. The awards included on the table are outstanding as of December 30, 2011.

(4) Values are based on a closing stock price for Williams of $33.02 on December 30, 2011.

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Supplemental Disclosure of Post-Spin-off Outstanding Equity Awards

The following table sets forth certain information with respect to the outstanding WPX Energy equity awards held by the NEOs after the spin-off. The conversion of Williams equity awards upon our spin-off is described above in Treatment of Outstanding Williams Long-Term Incentive Awards upon the Spin-Off section of our Compensation Discussion and Analysis. Since Mr. Chappel was not an NEO of WPX Energy after the spin-off, he is not included in this supplemental table.

		Option Award					Stock Awards				
Name	**Grant Date(1)**	**Number of Securities Underlying Unexercised Options(#) Exercisable (2)**	**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(3)**	**Market Value of Shares or Units of Stock That Have Not Vested(5)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units of Stock or Other Rights That Have Not Vested(4)**	**Equity Incentive Plan Award: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested(5)**
Ralph A. Hill	2/24/2011		72,490		16.46	2/24/2021	2/24/2011	39,258	713,318	39,258	713,318
	2/23/2010	30,605	61,210		11.75	2/23/2020	2/23/2010	55,521	1,008,817	55,521	1,008,817
	2/23/2009	113,118	56,560		6.02	2/23/2019	2/23/2009	112,320	2,040,854	112,320	2,040,854
	2/25/2008	69,710			20.21	2/25/2018					
	2/26/2007	78,775			15.67	2/26/2017					
Rodney A. Sailor	2/24/2011		18,678		16.46	2/24/2021	2/24/2011	9,995	181,609	6,247	113,508
	2/23/2010	6,984	13,972		11.75	2/23/2020	2/23/2010	12,403	225,363	7,752	140,854
	2/23/2009	20,490	10,247		6.02	2/23/2019	2/23/2009	19,321	351,063	12,075	219,403
	2/25/2008	16,510			20.21	2/25/2018					
	2/26/2007	17,068			15.67	2/26/2017					
	3/3/2006	15,422			12.00	3/3/2016					
	7/19/2005	1,335			11.32	7/19/2015					
	2/25/2005	4,006			10.68	2/25/2015					
James J. Bender	2/24/2011		55,434		16.46	2/24/2021	2/24/2011	30,021	545,482	30,021	545,482
	2/23/2010	22,733	45,472		11.75	2/23/2020	2/23/2010	41,244	749,403	41,244	749,403
	2/23/2009	86,502	43,251		6.02	2/23/2019	2/23/2009	85,891	1,560,639	85,891	1,560,639
	2/25/2008	55,033			20.21	2/25/2018					
	2/26/2007	52,517			15.67	2/26/2017					
	3/3/2006	43,603			12.00	3/3/2016					
Bryan K. Guderian	2/24/2011		19,230		16.46	2/24/2021	2/24/2011	10,292	187,006	6,431	116,851
	2/23/2010	7,983	15,968		11.75	2/23/2020	2/23/2010	14,176	257,578	8,859	160,968
	2/23/2009		11,710		6.02	2/23/2019	2/23/2009	22,081	401,212	13,800	250,746
	2/25/2008	21,429			20.21	2/25/2018					
	2/26/2007	26,258			15.67	2/26/2017					
Neal A Buck	2/24/2011		20,018		16.46	2/24/2021	2/24/2011	10,712	194,637	6,695	121,648
	2/23/2010	7,983	15,968		11.75	2/23/2020	2/23/2010	14,176	257,578	8,859	160,968
	2/23/2009	14,383	11,711		6.02	2/23/2019	2/23/2009	22,081	401,212	13,800	250,746
	2/25/2008	18,492			20.21	2/25/2018					
	2/26/2007	26,258			15.67	2/26/2017					
	3/3/2006	20,654			12.00	3/3/2016					
	2/25/2005	5,007			10.68	2/25/2015					

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 30, 2011.

Grant Date	Vesting Schedule	Vesting Dates
2/23/2011	One-third vests each year for three years	2/23/2012, 2/23/2013, 2/23/2014
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

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(2) The vested Williams stock options were converted to both Williams adjusted stock options and WPX Energy stock options. Only the resulting WPX Energy stock options are presented in the table above.

Name	Grant Date	Number of Unexercised Williams Stock Options Exercisable	Adjusted option Exercise Price	Expiration Date
Rodney J. Sailor	7/19/2005	4,006	16.64	7/19/2015
Rodney J. Sailor	2/25/2005	12,018	15.71	2/25/2015
Neal A. Buck	2/25/2005	15,022	15.71	2/25/2015

Stock Awards

(3) The following table reflects the vesting dates for associated time-based restricted stock unit award grant dates.

Grant Date	Vesting Schedule	Vesting Dates
2/23/2011	100% vests in three years	2/23/2014
2/23/2010	100% vests in three years	2/23/2013
2/25/2009	100% vests in three years	2/25/2012

(4) All performance-based RSUs are subject to attainment of performance targets established by the Compensation Committee. These awards will vest no earlier than the end of the performance period. The awards included on the table are outstanding as of December 30, 2011.

The supplemental values denominated in WPX Energy in this table are slightly different than those shown in the previous table which are denominated in Williams due to the conversion methodology that used volume weighted averaged stock prices and that truncated fractional shares.

(5) Values are based on a post-spin-off closing stock price for WPX Energy of $18.17 on December 30, 2011.

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2011 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
Ralph A. Hill	70,488	$ 767,385	15,132	$ 457,894
Donald R. Chappel			19,911	602,507
Rodney J. Sailor	19,649	396,340	3,584	108,452
James J. Bender	55,000	804,157	11,946	361,486
Bryan K. Guderian	53,042	590,608	4,652	140,770
Neal A. Buck	11,132	152,272	4,014	121,464

The Compensation Committee determines pay based on a target total compensation amount. While the Compensation 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 was significantly impacted by the stock market performance of both Williams and the Company s shares.

Pension Benefits

WPX Energy does not provide any qualified or nonqualified pension benefit for any NEOs or other employees.

Nonqualified Deferred Compensation

WPX Energy does not provide nonqualified deferred compensation for any NEOs or other employees.

Change in Control Agreements

Through December 31, 2011, Williams had entered into change in control agreements with certain officers, including each of our NEOs, to facilitate continuity of management if there was a change in control of Williams. The agreements between Williams and our NEOs were effective until our spin-off from Williams when our executives were no longer employees of Williams. WPX Energy entered into change in control agreements with certain officers, including each of our NEOs that were effective January 1, 2012. The provisions of WPX Energy s agreements are described. The definitions of words in quotations are also provided below.

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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:

		WPX Energy
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);		ü
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);		ü
A severance amount equal to a severance multiple times his/her base salary for the CEO and two times his/her base salary for the other 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);	Mr. Hill Other NEOs	3 times 2 times
Continued participation in the 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;		ü
All restrictions on stock options held by the NEO will lapse, and the options will vest and become immediately exercisable;		ü
All restricted stock will vest and will be paid out only in accordance with the terms of the respective award agreements;		ü
Continued participation in the directors and officers liability insurance for six years or any longer known applicable statute of limitations period;		ü
Indemnification as set forth under the Company s bylaws; and		ü
Outplacement benefits for six months at a cost not exceeding $25,000.		ü

Our agreements 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.

If a NEO s employment is terminated for cause during the period beginning upon a change in 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).

Our agreements with our NEOs effective January 1, 2012 both 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;

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willful or reckless material misconduct in the performance of his/her duties that has an adverse effect on WPX Energy or any of its subsidiaries or affiliates;

willful or reckless violation or disregard of the code of business conduct of WPX Energy or the policies of WPX Energy 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 the Board of Directors could determine that the NEO had satisfied the standards of conduct for indemnification or reimbursement under the Company s 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 in 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 the Company 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 the Company s counsel or required by the legal process.

Change in control means:

Any person or group (other than an affiliate of the Company or an employee benefit plan sponsored by the Company 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 the Company or 20% or more of the combined voting power of all securities entitled to vote generally in the election of directors of the Company (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;

The Company s 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 the Company;

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 the Company 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 shareholders of the Company of the sale or other disposition of all or substantially all of the consolidated assets of the Company or the complete liquidation of the company other than a transaction that would result in (i) a related party owning more than 50% of the assets that were owned by the Company immediately prior to the transaction or (ii) the persons who were the direct or indirect owners of outstanding common stock of the Company and Voting Securities prior to the transaction continuing to own, directly or indirectly, 50% or more of the assets that were owned by the Company 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 the Company s Board of Directors determines that a liquidation, sale or other disposition approved by the shareholders, as described in the fourth bullet above, will not occur, except to the extent termination occurred prior to such determination.

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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 Company plan for not less than three months.

Disqualification disaggregation means:

- the termination of a NEO s employment from the Company or an affiliate before a change in control for any reason; or
- the termination of a NEO s employment by a successor (during the period beginning upon a change in 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 Company s 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 the Company s peers, a successor company s failure to honor the agreement or the failure of the Company s Board of Directors to provide written notice of the act or omission constituting cause.

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Termination Scenarios

The following table sets forth circumstances that provide for payments by WPX Energy to the NEOs following or in connection with a change in control of WPX Energy or an NEO s termination of employment for cause, upon retirement, upon death and disability or not for cause, all while employed by WPX Energy on December 31, 2011 as of the time of the spin-off. NEOs are generally eligible to retire at the earlier of age 55 and completion of 3 years of service or age 65. Even though WPX Energy s agreements were effective January 1, 2012 after the spin-off, the agreements between the NEO and WPX Energy are presented below as a better representation of likely future payments in the event termination of an NEO should occur.

All values are based on a hypothetical termination date of December 30, 2011 and a closing stock price for WPX Energy common stock of $18.17 on the last trading day of the year, December 30, 2011. 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)(6)**
Ralph A. Hill	Stock options	$	$ 1,204,130	$ 1,204,130	$ 0	$ 1,204,130
	Stock awards		5,528,392	6,527,185	6,527,185	7,525,978
	Cash Severance					2,260,826
	Outplacement					25,000
	Health & Welfare					28,902
	Total	$	$ 6,732,522	$ 7,731,315	$ 6,527,185	$ 11,044,836
Rodney J. Sailor	Stock options	$	$ 246,140	$ 246,140	$ 0	$ 246,140
	Stock awards		851,684	1,085,600	1,085,600	1,231,799
	Cash Severance					1,009,362
	Outplacement					25,000
	Health & Welfare					29,262
	Total	$	$ 1,097,824	$ 1,331,740	$ 1,085,600	$ 2,541,563
James J. Bender	Stock options	$	$ 912,222	$ 912,222	$ 0	$ 912,222
	Stock awards		4,200,374	4,955,711	4,955,711	5,711,047
	Cash Severance					1,610,400
	Outplacement					25,000
	Health & Welfare					28,902
	Total	$	$ 5,112,596	$ 5,867,933	$ 4,955,711	$ 8,287,571
Bryan K. Guderian	Stock options	$	$ 277,675	$ 277,675	$ 0	$ 277,675
	Stock awards		963,905	1,216,510	1,216,510	1,374,360
	Cash Severance					1,171,500
	Outplacement					25,000
	Health & Welfare					18,470
	Total	$	$ 1,241,580	$ 1,494,185	$ 1,216,510	$ 2,867,005
Neal A. Buck	Stock options	$	$ 279,035	$ 279,035	$	$ 279,035
	Stock awards		967,420	1,225,498	1,225,498	1,386,788
	Cash Severance					1,138,500
	Outplacement					25,000

Health & Welfare					19,969
Total	$	$ 1,246,455	$ 1,504,533	$ 1,225,498	$ 2,849,292

(1) If an NEO is terminated for cause or leaves WPX Energy voluntarily, no additional benefits will be received.

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(2) If an NEO retires from WPX Energy, 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 Compensation 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 Compensation 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 Compensation Committee certifies that the performance measures were met. However all unvested stock options cancel.

(5) See Change in Control Agreements above.

(6) The cash severance amounts for Messrs. Hill and Sailor have been reduced $2,239,174 and $248,638, respectively, due to the net best provision.

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.

Compensation of Directors

Only non-employee directors receive director fees. Our Board of Directors was formed upon our spin-off from Williams, so no director compensation was paid to WPX Energy directors in 2011.

In 2012, the Company s non-employee directors will receive:

- $75,000 annual retainer in cash, paid quarterly; and

- $185,000 in the form of Restricted Stock Awards through the WPX Energy 2011 Incentive Plan, each non-employee director annually receives a form of long-term equity compensation as approved by the Nominating and Governance Committee.

The Chair of each of the Audit, Compensation, and Nominating and Governance Committees received an additional annual cash retainer of $15,000. Our non-executive chairman will receive additional compensation of $340,000 for his services each fiscal year of which $100,000 will be in cash and $240,000 will be in the form of restricted stock awards.

Non-employee directors will typically receive their equity on the date of the annual shareholders meeting. For 2012, the directors received five-twelve s of their annual equity grant in January 2012 after our successful spin-off from Williams, then will receive their annual equity grant in May 2012 when WPX Energy will hold the annual shareholders meeting in future years.

In the event that an individual becomes a non-employee director after an annual meeting, we have established the following procedures for compensating an individual for partial year service.

An individual who became a non-employee director	but before	will receive	as of
after the annual meeting	August 1	full compensation	December 15

on or after August 1	or on December 15	pro-rated compensation	December 15
on or after December 16	the next annual meeting	pro-rated compensation	the next annual meeting date

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Non-employee directors are reimbursed for expenses (including costs of travel, food, and lodging) incurred in attending Board, committee, and shareholder meetings. Directors are also reimbursed for reasonable expenses associated with other business activities, including participation in director education programs. Non-employee directors will be able to participate in matching gift programs to certain charitable organizations on the same basis as salaried employees of the Company.

Compensation Committee Interlocks and Insider Participation

On the Separation Date, our Compensation Committee was established and Messrs. Granberry, Lentz and Work were appointed members. None of these individuals has been an officer or employee of the Company or any of its subsidiaries at any time. In 2011, none of our executive officers served as a member of the board of directors or compensation committee of any other company that has one or more executive officers serving as a member of our Board or Compensation Committee.

Compensation Committee Report

This section of this Amendment No. 1 on Form 10-K/A will not be deemed incorporated by reference by any general statement incorporating by reference this Amendment No. 1 on Form 10-K/A into any filing under the Securities Act of 1933 or under the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and will not otherwise be deemed filed under these Acts.

The Compensation Committee has reviewed and discussed with management the section above entitled Compensation Discussion and Analysis. Based on this review and discussion, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Amendment No. 1 on Form 10-K/A to our Annual Report on Form 10-K for the year ended December 31, 2011.

William R. Granberry (Chairman)

Henry E. Lentz

David F. Work

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Securities Authorized for Issuance Under Equity Compensation Plans

We maintain two compensation plans under which shares of our common stock are authorized for issuance to plan participants: our 2011 Incentive Plan and our Employee Stock Purchase Plan. Each of these plans was approved by our stockholder prior to our separation from Williams.

The following table provides information as of December 31, 2011, about outstanding options and rights under these plans and shares reserved for future issuance under these plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	8,772,757	$ 11.40	12,000,000

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Security Ownership of Certain Beneficial Owners and Management

As of April 16, 2012, based on information known to us and filed with the SEC, there were no beneficial holders of five percent or more of our common stock. The following table sets forth certain information as of April 16, 2012, with respect to the number of shares of common stock owned by (a) each director of WPX, (b) each named executive officer of WPX, and (c) all directors and named executive officers of WPX as a group.

Name of Individual or Group	Shares of Common Stock Owned Directly or Indirectly(1)(2)	Shares Underlying Options Exercisable Within 60-Days(3)	Total	Percent of Class(4)
Kimberly S. Bowers	5,197	0	5,197	*
John A. Carrig	5,197	0	5,197	*
William R. Granberry	42,806	3,004	45,810	*
Don J. Gunther	5,197	0	5,197	*
Robert Herdman	5,197	0	5,197	*
Henry E. Lentz	5,197	0	5,197	*
George A. Lorch	114,966	0	114,966	*
William G. Lowrie	71,574	0	71,574	*
David F. Work	5,197	0	5,197	*
James R. Bender	360,659	344,851	705,510	*
Neal A. Buck	121,389	101,073	222,462	*
Donald R. Chappel	44,743	101,819	146,562	*
Bryan K. Guderian	118,603	81,770	200,373	*
Ralph A. Hill	572,221	403,535	975,756	*
Rodney J. Sailor	132,727	105,273	238,000	*
All directors and executive officers as a group (18 individuals)	1,924,044	1,443,925	3,367,969	1.7%

* Less than 1%

(1) Includes restricted stock units over which executive officers have no voting or investment power held under the terms of the WPX Energy, Inc. 2011 Incentive Plan as follows: Mr. Bender, 203,817; Mr. Buck, 86,419; Mr. Guderian, 86,783; Mr. Hill, 379,507; and Mr. Sailor, 104,814. Restricted stock units include both time-based and performance-based shares of common stock.

(2) Includes restricted stock units over which directors have no voting or investment power held under the terms of the WPX Energy, Inc. 2011 Incentive Plan as follows: Mr. Granberry, 33,626; Mr. Lorch, 100,204; and Mr. Lowrie, 33,626. For Mr. Lorch, includes 4,411 shares of deferred common stock that he has the right to receive at the end of a deferral period. Mr. Lorch has no voting or investment power over these deferred shares.

(3) The SEC deems a person to have beneficial ownership of all shares that the person has the right to acquire within sixty (60) days. The shares indicated represent stock options granted under the WPX Energy, Inc. 2011 Incentive Plan that are currently exercisable or will become exercisable within sixty (60) days of April 16, 2012. Shares subject to options cannot be voted.

(4) Ownership percentage is reported based on 198,714,249 shares of common stock outstanding on April 16, 2012, plus, as to the holder thereof and no other person, the number of shares (if any) that the person has the right to acquire as of April 16, 2012, or within 60 days of that date.

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CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Transactions with Related Persons

In 2011, we were a party to a number of transactions with Williams, our former parent company. The following is a summary of the types and amounts of such transactions.

Transaction Description	2011 Transaction Amount
Reimbursement of Expenses of Williams	
Payroll and benefits costs associated with operations employees	$ 132 million
General and administrative expense, including indirect employees	$ 140 million
Commodity Sales Contracts	
Sales of NGLs, natural gas for shrink replacement and fuel to Williams Partners and other Williams affiliates	$ 844 million
Gathering, Processing and Treating Contracts	
Gathering, processing and treating services purchased from Williams Partners	$ 298 million
Transportation Contracts	
Purchase of natural gas transportation services from Williams Partners	$ 44 million
Reimbursements from Williams Partners for transportation costs in connection with transportation capacity contract	$ 10.6 million
Derivative Contracts	
Revenues from contracts with Williams Partners to hedge Williams Partners forecasted NGL sales and natural gas purchases	$ 15.8 million

Procedures for Review and Approval of Related Party Transactions

The Board has adopted policies and procedures with respect to related person transactions as part of the Audit Committee charter. Any proposed related person transaction involving a member of the Board or the Chief Executive Officer must be reviewed and approved by the full Board. The Audit Committee reviews proposed transactions with any other related persons, promoters, and certain control persons. If it is impractical to convene an Audit Committee meeting before a related person transaction occurs, the chair of the committee may review the transaction alone.

No director may participate in any review, consideration or approval of any related person transaction with respect to which such director or any of his or her immediate family members is the related person. The Audit Committee or its chair, or the Board, as the case may be, in good faith, may approve only those related person transactions that are in, or not inconsistent with, WPX s best interests and the best interests of our stockholders. In conducting a review of whether a transaction is, or is not inconsistent with the best interest of WPX and its stockholders, the Audit Committee or its chair, or the Board, as the case may be, will consider the benefits of the transaction to the Company, 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 the Company and the related party, among other things. During 2011, there were no transactions that required review or approval by the Audit Committee or the full Board.

Director Independence

Our Corporate Governance Guidelines require that the Board make an annual determination regarding the independence of each of our directors. Based on an annual evaluation performed by and recommendations made by the Nominating and Governance Committee, the Board has determined that each of our current directors, other than Mr. Hill, is independent. The Board s determination of independence took into account the bright line standards of the NYSE as well as the absence of any material transactions or other relationships between the Company, on the one hand, and directors, their immediate family members and other associates, on the other.

The Board determined that Alan S. Armstrong and Donald R. Chappel, individuals who served on our Board prior to our separation from Williams, were not independent, owing to their roles as executive officers of Williams.

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DESCRIPTION OF OTHER INDEBTEDNESS

Credit Facility Agreement

During 2011 we entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility). Under the terms of the Credit Facility and subject to certain requirements, we 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 may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. At December 31, 2011 there was no outstanding balance under the Credit Facility.

The Credit Facility became effective on November 1, 2011. Also, on November 1, 2011 we terminated our existing unsecured credit agreement which had served to reduce margin requirements and transaction fees related to hedging activities. All outstanding hedges under the terminated agreement were transferred to new agreements with various financial institutions that also participate in the new Credit Facility. Neither we nor the participating financial institutions are required to provide collateral support related to hedging activities under the new agreements.

Interest on borrowings under the Credit Facility will be payable at rates per annum equal to, at the option of WPX Energy: (1) a fluctuating base rate equal to the Alternate Base Rate plus the Applicable Rate (each as defined in the Credit Facility) or (2) a periodic fixed rate equal to LIBOR plus the Applicable Rate. The Alternate Base Rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. The Applicable Rate changes depending on which interest rate WPX selects and WPX s credit rating. Additionally, WPX Energy will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility.

Under the Credit Facility, prior to the occurrence of the Investment Grade Date (as defined below), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (each as defined in the Credit Facility) of at least 1.50 to 1.00. Net present value 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 (such cash flows adjusted to reflect the impact of hedges, our lenders commodity price forecasts, and, if necessary, including only a portion of our reserves that are not proved developed producing reserves). Additionally, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. Beginning December 31, 2011, each of the above ratios will be tested at the end of each fiscal quarter. We were in compliance with our debt covenant ratios as of December 31, 2011. Investment Grade Date means the first date on which our 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 contains customary representations and warranties and affirmative, negative and financial covenants which were made only for the purposes of the Credit Facility 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 our subsidiaries to incur indebtedness, make investments, loans or advances and enter into certain hedging agreements; our ability to merge or consolidate with any person or sell all or substantially all of our 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 our business. In addition, the representations, warranties and covenants contained in the Credit Facility may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors.

The Credit Facility 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 us occurs under the Credit Facility, the lenders will be able to terminate the commitments and accelerate the maturity of any loans outstanding under the Credit Facility at the time, in addition to the exercise of other rights and remedies available.

Letters of Credit

In addition to the notes and Credit Facility, WPX has executed three bilateral, uncommitted letter of credit (LC) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility. At December 31, 2011 a total of $292 million in letters of credit have been issued.

Other

Apco executed a loan agreement with a financial institution for a $10 million bank line of credit. Borrowings under this facility are unsecured and bear interest at six-month LIBOR plus three percent per annum plus a one percent arrangement fee per borrowing and a commitment fee for the unused portion of the loan amount. The one-year period during which Apco could borrow funds ended in March 2012. Principal amounts will be repaid in semi-annual installments from each borrowing date after a two-and-a-half-year grace period. This debt agreement contains covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, purchase or sell assets outside the ordinary course of business, and incur additional debt. As of December 31, 2011, Apco has borrowed $2 million under this banking agreement. Aggregate minimum maturities of this long-term debt are $1 million each for 2013 and 2014.

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DESCRIPTION OF THE NOTES

You can find the definitions of certain terms used in this description under the subheading Certain Definitions. In this description, the term WPX refers only to WPX Energy, Inc. and not to any of its subsidiaries.

We will issue up to $400,000,000 in aggregate principal amount of 2017 notes and up to $1,100,000,000 in aggregate principal amount of 2022 notes under an indenture dated as of November 14, 2011, between WPX and The Bank of New York Mellon Trust Company, N.A., as trustee. The terms of the exchange notes are identical in all material respects to the terms of the outstanding notes, except the exchange notes will not contain transfer restrictions and holders of exchange notes will no longer have any registration rights and we will not be obligated to pay Additional Interest as described in the registration rights agreement. We refer to exchange notes and outstanding notes (to the extent not exchanged for exchange notes) in this section as the notes. The terms of the notes will include those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act of 1939, as amended (the *Trust Indenture Act*).

The following description is a summary of the material provisions of the indenture and the notes. It does not restate those agreements in their entirety. We urge you to read the indenture in its entirety because it, and not this description, define your rights as holders of the notes. Copies of the indenture are available as set forth below under Additional Information. Certain defined terms used in this description but not defined below under Certain Definitions have the meanings assigned to them in the indenture.

The registered holder of a note will be treated as the owner of it for all purposes. Only registered holders will have rights under the indenture.

Brief Description of the Notes:

The notes:

- are our general unsecured obligations;
- are equal in right of payment with all of our existing and future senior unsecured indebtedness; and
- are effectively subordinated to any of our existing and future senior secured indebtedness and structurally subordinated to all existing and future indebtedness and other obligations of our Subsidiaries, including trade payables.

As of December 31, 2011:

- We had outstanding indebtedness of approximately $1.5 billion (including $1.5 billion in aggregate principal amount of the notes); and
- our Subsidiaries had outstanding indebtedness of $2.0 million.

The indenture will permit us to incur additional indebtedness, including additional senior unsecured indebtedness. The indenture also will not restrict the ability of our subsidiaries to incur additional indebtedness. See Risk Factors Risk Relating to the Notes Our indebtedness could impair our financial condition and our ability to fulfill our debt obligations, including our obligations under the notes.

Principal, Maturity and Interest

We will issue up to $400,000,000 in aggregate principal amount of 2017 notes and up to $1,100,000,000 in aggregate principal amount of 2022 notes in exchange for outstanding 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022, respectively, that are validly tendered at or before the expiration time and not validly withdrawn. The 2017 notes will mature on January 15, 2017 and the 2022 notes will mature on January 15, 2022. We will issue notes in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Interest on the 2017 notes will accrue at the rate of 5.250% per annum, and will be payable semiannually in arrears on January 15 and July 15, beginning on July 15, 2012. We will make each interest payment on the 2017 notes to the holders of record at the close of business on the immediately preceding January 1 or July 1 (whether or not a Business Day). Interest on the 2022 notes will accrue at the rate of 6.000% per annum, and will be payable semi-annually in arrears on January 15 and July 15, beginning on July 15, 2012. We will make each interest payment on the 2022 notes to the holders of record at the close of business on the immediately preceding January 1 or July 1 (whether or not a Business Day).

Holders whose outstanding notes are exchanged for exchange notes will not receive a payment in respect of interest accrued but unpaid on such outstanding notes from the original issue date of the outstanding notes or the most recent interest payment date up to but excluding the settlement date. Instead, interest on the exchange notes received in exchange for such outstanding notes will (i) accrue from the last date on which interest was paid on such outstanding notes or, if no interest has been paid on such outstanding notes, from the original issue date of such outstanding notes and (ii) accrue at the same rate as and be payable on the same dates as interest was payable on such outstanding notes. However, if any interest payment occurs prior to the settlement date on any outstanding notes already tendered for exchange in the exchange offer, the holder of such outstanding notes will be entitled to receive such interest payment.

Interest on the notes will otherwise accrue from the date it was most recently paid or duly provided for. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months.

We may, without the consent of the holders of notes of any series, issue additional notes having the same ranking and the same interest rate, maturity and other terms as the notes of such series, except that interest may accrue from the date of issuance of such additional notes and such additional notes may not be fungible for trading purposes with, and may initially bear different identifying numbers than, the notes of the applicable series offered hereby. Any additional notes having such similar terms, together with the notes of the applicable series offered hereby, will constitute a single series of notes under the indenture.

Methods of Receiving Payments on the Notes

We will pay all principal, interest and premium, if any, on the notes in the manner described under Same Day Settlement and Payment below.

Paying Agent and Registrar for the Notes

The trustee will initially act as paying agent and registrar. We may change the paying agent or registrar without prior notice to the holders of the notes, and we or any of our Subsidiaries may act as paying agent or registrar.

Transfer and Exchange

A holder may transfer or exchange notes in accordance with the indenture. The registrar and the trustee may require a holder to furnish appropriate endorsements and transfer documents in connection with a transfer of notes. No service charges will be imposed by us, the trustee or the registrar for any registration of transfer or exchange of notes, but holders may be required to pay all taxes due on transfer or exchange. We are not required to transfer or exchange any note selected for redemption, except the unredeemed portion of any note being redeemed in part. Also, we are not required to transfer or exchange any note for a period of 15 days before mailing notice of any redemption of notes.

Optional Redemption

We may, at our option, prior to maturity, in the case of the 2017 notes, and prior to October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes), in the case of the 2022 notes, redeem the notes of any series, in whole or in part, at any time or from time to time, upon not less than 30 nor more than 60 days notice, at a redemption price equal to the greater of:

(1) 100% of the principal amount of the notes to be redeemed, plus accrued interest to the redemption date, and

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(2) as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal of and interest on the notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) discounted to the redemption date on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 50 basis points in the case of the 2017 notes and 50 basis points in the case of the 2022 notes, plus accrued interest to but excluding the redemption date (provided, in each case, that interest payments due on or prior to the redemption date will be paid to the record holders of such notes on the relevant record date).

We also have the option at any time on or after October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes) to redeem the 2022 notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus accrued and unpaid interest thereon to the redemption date.

Selection and Notice

If less than all of the notes of any series are to be redeemed at any time, the trustee will select such notes for redemption from the outstanding notes of such series not previously called for redemption by such method as the trustee shall deem fair and appropriate.

No notes of $2,000 or less can be redeemed in part. Notices of optional redemption will be mailed by first class mail at least 30 but not more than 60 days before the redemption date to each holder of notes to be redeemed at its registered address. Notices of redemption may not be conditional.

If any note is to be redeemed in part only, the notice of redemption that relates to that note will state the portion of the principal amount of that note that is to be redeemed. A new note of the same series and in principal amount equal to the unredeemed portion of the original note will be issued in the name of the holder of notes upon cancellation of the original note. Notes called for redemption become due on the date fixed for redemption. On and after the redemption date, interest will cease to accrue on notes or portions of them called for redemption.

Change of Control

If a Change of Control occurs and is accompanied by a Rating Decline of a series of the notes (together, a *Change of Control Triggering Event*), each registered holder of the notes of such series will have the right to require us to offer to repurchase all or any part (equal to $1,000 or an integral multiple of $1,000 in excess thereof, provided that the unpurchased portion of any note must be in a minimum denomination of $2,000) of such holder s notes of such series at a purchase price in cash equal to 101% of the principal amount of such notes plus accrued and unpaid interest, if any, to the date of purchase.

Within 30 days following any Change of Control Triggering Event, we will mail a notice (the *Change of Control Offer*) to each registered holder of notes of such series with a copy to the trustee stating:

(1) that a Change of Control Triggering Event has occurred and that such holder has the right to require us to purchase such holder s notes at a purchase price in cash equal to 101% of the principal amount of such notes plus accrued and unpaid interest, if any, to the date of purchase (the *Change of Control Payment*);

(2) the repurchase date (which shall be no earlier than 30 days nor later than 60 days from the date such notice is mailed and which may be up to five days after the expiration of the Change of Control Offer) (the *Change of Control Payment Date*); and

(3) the procedures determined by us, consistent with the indenture, that a holder must follow in order to have its notes repurchased.

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On the Change of Control Payment Date we will, to the extent lawful:

(1) accept for payment all notes or portions thereof (in integral multiples of $1,000 or an integral multiple of $1,000 in excess thereof; provided that the unpurchased portion of any note must be in a minimum denomination of $2,000) properly tendered and not withdrawn under the Change of Control Offer;

(2) deposit with the paying agent an amount equal to the Change of Control Payment in respect of all notes or portions thereof so tendered; and

(3) deliver or cause to be delivered to the trustee the notes so accepted together with an Officers Certificate stating the aggregate principal amount of such notes or portions thereof being purchased by us.

The Paying Agent will promptly mail or otherwise deliver to each holder of notes so tendered the Change of Control Payment for such notes, and the trustee will promptly authenticate and mail (or cause to be transferred by book entry) to each holder a new note of the applicable series equal in principal amount to any unpurchased portion of the notes of the applicable series surrendered, if any; provided that each such new note of the applicable series will be in a principal amount of $2,000 or an integral multiple of $1,000 in excess thereof.

If the Change of Control Payment Date is on or after an interest record date and on or before the related interest payment date of a series of notes, accrued and unpaid interest, if any, will be paid to the person in whose name such note is registered at the close of business on such record date, and no Additional Interest will be payable to holders who tender pursuant to the Change of Control Offer.

Except as described above with respect to a Change of Control Triggering Event, the indenture does not contain provisions that permit the holders to require that we repurchase or redeem the notes of any series in the event of a takeover, recapitalization or similar transaction.

We will not be required to make a Change of Control Offer upon a Change of Control Triggering Event if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the indenture applicable to a Change of Control Offer made by us and purchases all notes validly tendered and not withdrawn under such Change of Control Offer.

Our and our subsidiaries current and/or future debt instruments may require that we repay or refinance indebtedness under such debt instruments in the event of a change of control, as defined in such debt instruments. Such change of control provisions may be triggered under such debt instruments prior to the occurrence of a Change of Control Triggering Event, thereby requiring that the indebtedness under such debt instruments be repaid or refinanced prior to our repurchasing any notes upon the occurrence of a Change of Control Triggering Event. Moreover, the exercise by the holders of their right to require us to repurchase the notes could cause a default under such debt instruments, even if the Change of Control Triggering Event itself does not, due to the financial effect of such repurchase on us. In such event, we may not be able to satisfy our obligations to repurchase the notes unless we are able to refinance or obtain waivers with respect to such debt instruments.

Finally, our ability to pay cash to the holders upon a repurchase may be limited by our then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases.

Even if sufficient funds were otherwise available, the terms of our current and/or future debt instruments may prohibit our prepayment of notes of any series before their scheduled maturity. Consequently, if we are not able to prepay the indebtedness under such debt instruments or obtain requisite consents, we will be unable to fulfill our repurchase obligations if holders of the notes of any series exercise their repurchase right following a Change of Control Triggering Event, resulting in an Event of Default under the indenture. An Event of Default under the indenture may result in a default under our current and/or future debt instruments.

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We will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with the repurchase of the notes as a result of a Change of Control Triggering Event. To the extent that the provisions of any such securities laws or regulations conflict with the Change of Control offer provisions of the notes, we will comply with those securities laws and regulations and will not be deemed to have breached our obligations under the Change of Control offer provisions of the notes by virtue of any such conflict.

The definition of Change of Control includes a phrase relating to the sale, lease, transfer, conveyance or other disposition of all or substantially all of our assets and those of our subsidiaries taken as a whole. Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve all or substantially all of the properties or assets of a Person.

In addition, under clause (4) of the definition of Change of Control below, a Change of Control will occur when a majority of the members of the board of directors or equivalent governing body of WPX ceases to be composed of individuals (i) who were members of that board or equivalent governing body on the date the notes were issued, (ii) whose election or nomination to that board or equivalent governing body was approved by individuals referred to in clause (i) above constituting at the time of such election or nomination at least a majority of that board or equivalent governing body, or (iii) whose election or nomination to that board or equivalent governing body was approved by individuals referred to in clauses (i) and (ii) above constituting at the time of such election or nomination at least a majority of that board or equivalent governing body (excluding, in the case of both clause (ii) and clause (iii), any individual whose initial nomination for, or assumption of office as, a member of that board or equivalent governing body occurs as a result of an actual or threatened solicitation of proxies or consents for the election or removal of one or more directors by any person or group other than a solicitation for the election of one or more directors by or on behalf of the board of directors). In San Antonio Fire & Police Pension Fund v. Amylin Pharmaceuticals, Inc. et al. (May 2009), the Delaware Court of Chancery held that the occurrence of a change of control under a similar indenture provision may nevertheless be avoided if the existing directors were to approve the slate of new director nominees, provided the existing directors gave their approval in the good faith exercise of their fiduciary duties owed to the corporation and its shareholders. Therefore, in certain circumstances involving a significant change in the composition of our Board of Directors, holders of the Notes may not be entitled to require us to repurchase the Notes as described above.

Mandatory Redemption

We are not required to make mandatory redemption or sinking fund payments with respect to the notes of any series.

Certain Covenants

Except as set forth in this Description of the Notes, neither we nor any of our Subsidiaries will be restricted by the indenture from incurring additional indebtedness or other obligations, from making distributions or paying dividends on our or our Subsidiaries equity interests or from purchasing our or our Subsidiaries equity interests. The indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity. In addition, the indenture does not contain any provisions that would require us to repurchase or redeem any of the notes in situations that may adversely affect the creditworthiness of the notes.

Liens

We will not, and will not permit any Subsidiary of ours to, issue, assume or guarantee any Indebtedness secured by a Lien, other than Permitted Liens, upon any of our or any of our Subsidiaries property, now owned or hereafter acquired, unless the notes are equally and ratably secured with such Indebtedness until such time as such Indebtedness is no longer secured by a Lien.

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Notwithstanding the preceding paragraph, we may, and may permit any Subsidiary of ours to, issue, assume or guarantee any Indebtedness secured by a Lien, other than a Permitted Lien, without securing the notes; provided that the aggregate principal amount of all Indebtedness of ours and any Subsidiary of ours then outstanding secured by any such Liens (other than Permitted Liens) does not exceed 15% of Consolidated Net Tangible Assets.

Merger, Consolidation or Sale of Assets

We may not directly or indirectly consolidate with or merge with or into, or sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of our assets and properties and the assets and properties of our Subsidiaries (taken as a whole) in one or more related transactions to another Person, unless:

(1) either: (a) we are the survivor; or (b) the Person formed by or surviving any such consolidation or merger (if other than us) or to which such sale, assignment, transfer, lease, conveyance or other disposition has been made is a Person formed, organized or existing under the laws of the United States, any state of the United States or the District of Columbia;

(2) the Person formed by or surviving any such consolidation or merger (if other than us) or the Person to which such sale, assignment, transfer, lease, conveyance or other disposition has been made expressly assumes by supplemental indenture, in form reasonably satisfactory to the trustee, executed by the successor person and delivered to the trustee, the due and punctual payment of the principal of and any premium and interest on the notes of each series and the performance of all of our obligations under the indenture, the notes of each series and, if applicable, the registration rights agreement;

(3) we or the Person formed by or surviving any such merger will deliver to the trustee an officer s certificate and an opinion of counsel, each stating that such consolidation, merger, sale, assignment, transfer, lease, conveyance or other disposition and such supplemental indenture (if any) comply with the indenture and that all conditions precedent in the indenture relating to such transaction have been complied with; and

(4) immediately after giving effect to such transaction, no Event of Default or event which, after notice or lapse of time, or both, would become an Event of Default, shall have occurred and be continuing.

Upon any consolidation by us with or our merger into any other Person or Persons where we are not the survivor or any sale, assignment, transfer, lease, conveyance or other disposition of all or substantially all of our properties and assets and the properties and assets of our Subsidiaries (taken as a whole) to any Person or Persons in accordance herewith, the successor Person formed by such consolidation or into which we are merged or to which such sale, assignment, transfer, lease, conveyance or other disposition is made shall succeed to, and be substituted for, and may exercise every right and power of, us under the indenture with the same effect as if such successor Person had been named as WPX therein; and thereafter, except in the case of a lease, the predecessor Person shall be released from all obligations and covenants under the indenture and the notes.

Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve all or substantially all of the properties or assets of a Person.

Reports

We will:

(1) file with the trustee, within 30 days after we have filed the same with the Commission, unless such reports are available on the Commission s EDGAR filing system (or any successor thereto), copies of the annual reports and of the information, documents, and other reports (or copies of such portions of any of the foregoing as the Commission may from time to time by rules and regulations prescribe)

which we may be required to file with the Commission pursuant to Section 13 or Section 15(d) of the Exchange Act; or, if we are not required to file information, documents or reports pursuant to either of said Sections, then we shall file with the trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such of the supplementary and periodic information, documents, and reports which may be required pursuant to Section 13 of the Exchange Act in respect of a security listed and registered on a national securities exchange as may be prescribed from time to time in such rules and regulations;

(2) file with the trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such additional information, documents and reports with respect to compliance by us with the conditions and covenants of the indenture as may be required from time to time by such rules and regulations; and

(3) transmit to the holders of the notes within 30 days after the filing thereof with the trustee, in the manner and to the extent provided in Section 313(c) of the Trust Indenture Act, such summaries of any information, documents and reports required to be filed by us pursuant to clauses (1) and (2) of this paragraph as may be required by rules and regulations prescribed from time to time by the Commission.

In addition, so long as the notes of any series remain outstanding, we will make available to all holders of such notes and to securities analysts and prospective investors in such notes, upon request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act unless such information is available on the Commission s EDGAR filing system (or any successor thereto).

Events of Default and Remedies

Each of the following is an Event of Default under the indenture with respect to the notes of any series:

(1) a default in the payment of interest on the notes of such series when due that continues for 30 days;

(2) a default in the payment of the principal of or any premium, if any, on the notes of such series when due at their stated maturity, upon redemption, or otherwise;

(3) failure by WPX duly to observe or perform any other of the covenants or agreements (other than those described in clause (1) or (2) above) in the indenture, which failure continues for a period of 60 days, or, in the case of the covenant set forth under Certain Covenants Reports above, which failure continues for a period of 90 days, after the date on which written notice of such failure, requiring the same to be remedied and stating that such notice is a Notice of Default has been given to us by the trustee, upon direction of holders of at least 25% in principal amount of then outstanding notes of such series; provided, however, that if such failure is not capable of cure within such 60-day or 90-day period, as the case may be, such 60-day or 90-day period, as the case may be, shall be automatically extended by an additional 60 days so long as (i) such failure is subject to cure, and (ii) WPX is using commercially reasonable efforts to cure such failure; and

(4) certain events of bankruptcy, insolvency or reorganization described in the indenture.

In case an Event of Default specified in clause (1) or (2) above shall occur and be continuing with respect to the notes of any series, holders of at least 25%, and in case an Event of Default specified in clause (3) above shall occur and be continuing with respect to the notes, holders of at least a majority, in aggregate principal amount of the notes of such series then outstanding may declare the principal to be due and payable. If an Event of Default described in clause (4) above shall occur and be continuing then the principal amount of all the notes of such series then outstanding under the indenture shall be and become due and payable immediately, without notice or other action by any holder or the trustee, to the full extent permitted by law.

Holders of the notes may not enforce the indenture or the notes except as provided in the indenture. Subject to certain limitations, holders of a majority in principal amount of the then outstanding notes of any series may

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direct the trustee in its exercise of any trust or power with respect to the notes of such series. The indenture provides that the trustee may withhold notice to the holders of notes of any series of any default with respect to the notes of such series (except in payment of principal of or interest or premium on the notes of such series) if the trustee considers it in the interest of holders to do so.

Holders of not less than a majority in principal amount of the notes of any series, then outstanding by notice to the trustee may on behalf of the holders of all of the notes of such series, waive any past or existing default or Event of Default under the indenture with respect to such series and its consequences, except a continuing default (a) in the payment of principal of, or interest or premium, if any, on the notes of such series or (b) in respect of a covenant or other provision of the indenture, which under the indenture cannot be modified or amended without the consent of the holder of each outstanding note of such series.

We are required to deliver to the trustee annually a statement regarding compliance with the indenture.

Waiver, Modification and Amendment

We and the trustee may modify and amend the indenture with the consent of the holders of a majority in aggregate principal amount of the outstanding notes of any series affected by such amendment, provided that no such modification or amendment may, without the consent of the holder of each note of any series affected thereby:

(1) change the stated maturity of the principal of, or scheduled date for the payment of any installment of interest on, any note of such series;

(2) reduce the principal amount of, the rate of interest payable on, or any premium payable upon the redemption of, any note of such series;

(3) change the place of payment for any note of such series or the currency in which the principal of, or any premium or interest on, any note of such series is payable;

(4) impair or affect the right to institute suit for the enforcement of any payment of principal, premium, or interest on or with respect to any note of such series after the date that such payment has become due and payable;

(5) change the provisions related to a Change of Control Offer; or

(6) reduce the percentage in principal amount of outstanding notes of such series the consent of whose holders is required for any supplemental indenture amending or modifying the indenture or any waiver (of certain defaults and their consequences) provided for in the indenture or reduce the requirements contained in the indenture for quorum or voting.

A supplemental indenture that changes or eliminates any covenant or other provision of the indenture that has been included expressly and solely for the benefit of one or more particular series of notes, or that modifies the rights of holders of notes of such series with respect to such covenant or other provision, are deemed not to affect the rights under the indenture of the holders of notes of any other series.

The indenture provides that we and the trustee may, at any time and from time to time, without the consent of any holders of the notes of any series, enter into one or more supplemental indentures, in form satisfactory to the trustee, for any of the following purposes:

(1) to evidence the succession of another person to us, and the assumption by any such successor of our covenants in the indenture, the notes and the registration rights agreement;

(2) to add to our covenants for the benefit of the holders of all or any series of the notes (as shall be specified in such supplemental indenture or indentures) or to surrender any right or power in the indenture conferred on us;

(3) to evidence and provide for acceptance of appointment of a successor trustee under the indenture with respect to the notes of one or more series and to add to or change any of the provisions of the indenture as shall be necessary to provide for or facilitate the administration of the trusts under the indenture by more than one trustee;

(4) to cure any ambiguity, to correct or supplement any provision in the indenture that may be defective or inconsistent with any other provision of the indenture, or to make any other provisions with respect to matters or questions arising under such indenture; provided that no such action pursuant to this clause (4) shall adversely affect the interests of the holders of the notes of any series then outstanding in any material respect;

(5) to add any additional Events of Default with respect to all or any series of notes (as shall be specified in such supplement indenture);

(6) to supplement any of the provisions of the indenture to such extent as shall be necessary for the defeasance and discharge of any series of notes pursuant to Discharge, Legal Defeasance and Covenant Defeasance ; provided that any such action shall not adversely affect the interests of any holder of any outstanding note of such series or any other note in any material respect;

(7) to add guarantees in respect of the notes of one or more series and to provide for the terms and conditions of release thereof;

(8) to convey, transfer, assign, mortgage or pledge to the trustee as security for the notes of one or any series any property or assets and to provide for the terms and conditions of any release thereof;

(9) to provide for definitive notes in addition to or in place of global notes;

(10) to qualify the indenture under the Trust Indenture Act of 1939, as amended;

(11) to provide for the issuance of additional notes in accordance with the limitations set forth in the indenture;

(12) to conform the text of the indenture or the notes of any series to any provision of this Description of the Notes to the extent that such provision in this Description of the Notes, in our good faith judgment, was intended to be a verbatim recitation of a provision of the indenture or such notes; or

(13) to make any other change that does not adversely affect the rights of holders of outstanding notes in any material respect.

Discharge, Legal Defeasance and Covenant Defeasance

The indenture provides that we may satisfy and discharge our obligations under the notes of any series and the indenture with respect to such series if:

(1) either:

(a) all notes of such series previously authenticated and delivered have been delivered to the trustee for cancellation, except mutilated, lost, stolen or destroyed notes of such series that have been replaced or paid and notes of such series for whose payment money has been deposited in trust and thereafter repaid to us or discharged from such trust; or

(b) all such notes of such series not delivered to the trustee for cancellation have become due and payable, mature within one year, or are to be called for redemption within one year under arrangements satisfactory to the trustee for giving the notice of redemption and we irrevocably deposit or cause to be deposited in trust with the trustee, as trust funds solely for the benefit of the holders, for such purpose, money sufficient, governmental obligations, the scheduled payments of principal of and interest on which shall be sufficient, or a combination thereof sufficient (in the opinion of a nationally recognized independent registered public accounting firm expressed in a written certification thereof delivered to the trustee, which opinion need be given only if governmental obligations have been so deposited) without consideration of any reinvestment to pay and discharge the entire indebtedness on such then outstanding notes to maturity or earlier redemption, as the case may be; and

(2) we pay or cause to be paid all other sums payable by us under such indenture with respect to outstanding notes of such series; and

(3) we deliver to the trustee an officers certificate and an opinion of counsel, in each case stating that all conditions precedent provided for in the indenture relating to the satisfaction and discharge of the indenture as to such series have been complied with.

Notwithstanding such satisfaction and discharge with respect to any series of notes, our obligations to compensate and indemnify the trustee and our and the trustee s obligations to hold funds in trust and to apply such funds pursuant to the terms of the indenture with respect to the notes of such series, with respect to issuing temporary notes of such series, with respect to the registration, transfer and exchange of notes of such series, with respect to the replacement of mutilated, destroyed, lost or stolen notes of such series and with respect to the maintenance of an office or agency for payment with respect to the notes of such series, shall in each case survive such satisfaction and discharge.

The indenture provides that (i) we will be deemed to have paid and will be discharged from any and all obligations in respect of the notes of a series, and the provisions of the indenture will, except as noted below, no longer be in effect with respect to the notes of such series (*defeasance*) and (ii) we may, with respect to a series of notes, omit to comply with the covenants under Liens and Merger, Consolidation or Sale of Assets, and such omission shall be deemed not to be an event of default under clause (3) of the first paragraph of Events of Default and Remedies with respect to the notes of such series (*covenant defeasance*) and provided that the following conditions shall have been satisfied:

(1) we have irrevocably deposited or caused to be deposited in trust with the trustee as trust funds solely for the benefit of the holders of such notes, money sufficient or government obligations, the scheduled payments of principal of and interest on which shall be sufficient, or a combination thereof sufficient (in the opinion of a nationally recognized independent registered public accounting firm expressed in a written certification thereof delivered to the trustee) without consideration of any reinvestment to pay and discharge the principal of and accrued interest on such then outstanding notes to maturity or earlier redemption, as the case may be;

(2) such defeasance or covenant defeasance will not result in a breach or violation of, or constitute a default under, the indenture or any other material agreement or instrument to which we are a party or by which we are bound;

(3) no Event of Default or event which with notice or lapse of time would become an Event of Default with respect to such notes shall have occurred and be continuing on the date of such deposit (other than an Event of Default resulting from non-compliance with any covenant from which WPX is released upon effectiveness of such defeasance or covenant defeasance as applicable);

(4) we shall have delivered to the trustee an opinion of counsel as described in the indenture to the effect that: the holders of the notes of such series will not recognize income, gain or loss for federal income tax purposes as a result of our exercise of the option under this provision of the indenture and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit and defeasance or covenant defeasance had not occurred;

(5) we have delivered to the trustee an officers certificate and an opinion of counsel, in each case stating that all conditions precedent provided for in the indenture relating to the defeasance or covenant defeasance have been complied with; and

(6) if the notes of such series are to be redeemed prior to their maturity, notice of such redemption shall have been duly given or provision therefor satisfactory to the trustee shall have been made.

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Notwithstanding a defeasance or covenant defeasance with respect to the notes of a series, our obligations with respect to the following will survive until otherwise terminated or discharged under the terms of the indenture or until no notes of such series are outstanding:

(1) the rights of holders to receive payments in respect of the principal of, interest on or premium, if any, on such notes when such payments are due from the trust referred in clause (1) in the preceding paragraph;

(2) the issuance of temporary notes of such series, the registration, transfer and exchange of notes of such series, the replacement of mutilated, destroyed, lost or stolen notes of such series and the maintenance of an office or agency for payment and holding payments in trust with respect to the notes of such series;

(3) the rights, powers, trusts, duties and immunities of the trustee, and our obligations in connection therewith; and

(4) the defeasance provisions of the indenture.

No Personal Liability

None of any affiliate, director, officer, partner, employee, incorporator, manager or owner of Capital Stock of us, as such, will have any liability for any of our obligations under the notes, the indenture, or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder of notes by accepting a note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the notes. The waiver may not be effective to waive liabilities under the federal securities laws.

Notices

Notices to holders of the notes will be given by mail to the addresses of such holders as they appear in the security register.

Title

We or the trustee may treat the registered owner of any registered debt security as the owner thereof (whether or not the debt security shall be overdue and notwithstanding any notice to the contrary) for the purpose of making payment and for all other purposes.

Governing Law

The indenture and the notes will be governed by, and construed in accordance with, the laws of the State of New York.

Concerning the Trustee

The Bank of New York Mellon Trust Company, N.A. is the trustee under the indenture. If the trustee becomes a creditor of ours, the indenture limits its right to obtain payment of claims in certain cases or to realize on certain property received in respect of any such claim as security or otherwise. The trustee will be permitted to engage in other transactions; however, if the trustee acquires any conflicting interest (as defined in the Trust Indenture Act) after a default has occurred and is continuing, it must eliminate such conflict within 90 days, apply to the Commission for permission to continue or resign.

The holders of a majority in principal amount of the then outstanding notes of any series, will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the trustee with respect to the notes of such series, subject to certain exceptions. The indenture provides that in case an Event of Default occurs and is continuing, the trustee will be required, in the exercise of its power, to use the degree of care of a prudent person in the conduct of such person s own affairs. Subject to such provisions, the trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any holder of notes, unless such holder has offered to the trustee security or indemnity satisfactory to it against any loss, liability or expense.

Additional Information

Anyone who receives this prospectus may obtain a copy of the indenture and the registration rights agreement without charge by writing to WPX Energy, Inc., One Williams Center, Tulsa, Oklahoma 74172-0172; Attention: Chief Financial Officer.

Book-Entry, Delivery and Form

Except as set forth below, the notes will be issued in registered, global form (the *Global Notes*) in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. Notes will be issued at the closing of this offering only against payment in immediately available funds.

The Global Notes will be deposited upon issuance with the trustee as custodian for The Depository Trust Company (DTC), and registered in the name of DTC or its nominee, in each case, for credit to an account of a direct or indirect participant in DTC as described below.

Except as set forth below, the Global Notes may be transferred, in whole but not in part, only to DTC, to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for definitive notes in registered certificated form (Certificated Notes) except in the limited circumstances described below. See Exchange of Global Notes for Certificated Notes. Except in the limited circumstances described below, owners of beneficial interests in the Global Notes will not be entitled to receive physical delivery of notes in certificated form.

Transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants (including, if applicable, those of Euroclear and Clearstream), which may change from time to time.

Depository Procedures

The following description of the operations and procedures of DTC, Euroclear and Clearstream are provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. WPX takes no responsibility for these operations and procedures and urge investors to contact the system or their participants directly to discuss these matters.

DTC has advised WPX that DTC is a limited-purpose trust company created to hold securities for its participating organizations (collectively, the *Participants*) and to facilitate the clearance and settlement of transactions in those securities between the Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers (including the initial purchasers), banks, trust companies, clearing corporations and certain other organizations. Access to DTC s system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the *Indirect Participants*). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through the Participants or the Indirect Participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and Indirect Participants.

DTC has also advised WPX that, pursuant to procedures established by it:

(1) upon deposit of the Global Notes, DTC will credit the accounts of the Participants designated by the initial purchasers with portions of the principal amount of the Global Notes; and

(2) ownership of these interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the Participants) or by the Participants and the Indirect Participants (with respect to other owners of beneficial interests in the Global Notes).

Investors in the Global Notes who are Participants may hold their interests therein directly through DTC. Investors in the Global Notes who are not Participants may hold their interests therein indirectly through organizations (including Euroclear and Clearstream) which are Participants. Euroclear and Clearstream will hold interests in the Regulation S Global Notes on behalf of their participants through customers securities accounts in their respective names on the books of their respective depositories, which are Euroclear Bank S.A./N.V., as operator of Euroclear, and Citibank, N.A., as operator of Clearstream. All interests in a Global Note, including those held through Euroclear or Clearstream, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear or Clearstream may also be subject to the procedures and requirements of such systems. The laws of some jurisdictions may require that certain Persons take physical delivery in definitive form of securities that they own. Consequently, the ability to transfer beneficial interests in a Global Note to such Persons will be limited to that extent. Because DTC can act only on behalf of the Participants, which in turn act on behalf of the Indirect Participants, the ability of a Person having beneficial interests in a Global Note to pledge such interests to Persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of interests in the Global Notes will not have notes registered in their names, will not receive physical delivery of Certificated Notes and will not be considered the registered owners or holders thereof under the indenture for any purpose.

Payments in respect of the principal of, premium on, if any, and interest on, a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the indenture. Under the terms of the indenture, WPX and the trustee will treat the Persons in whose names the notes, including the Global Notes, are registered as the owners of the notes for the purpose of receiving payments and for all other purposes. Consequently, neither WPX, the trustee nor any agent of WPX or the trustee has or will have any responsibility or liability for:

(1) any aspect of DTC s records or any Participant s or Indirect Participant s records relating to or payments made on account of beneficial ownership interests in the Global Notes or for maintaining, supervising or reviewing any of DTC s records or any Participant s or Indirect Participant s records relating to the beneficial ownership interests in the Global Notes; or

(2) any other matter relating to the actions and practices of DTC or any of its Participants or Indirect Participants.

DTC has advised WPX that its current practice, upon receipt of any payment in respect of securities such as the notes (including principal and interest), is to credit the accounts of the relevant Participants with the payment on the payment date unless DTC has reason to believe that it will not receive payment on such payment date. Each relevant Participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the Participants and the Indirect Participants to the beneficial owners of notes will be governed by standing instructions and customary practices and will be the responsibility of the Participants or the Indirect Participants and will not be the responsibility of DTC, the trustee or WPX. Neither WPX nor the trustee will be liable for any delay by DTC or any of the Participants or the Indirect Participants in identifying the beneficial owners of the notes, and WPX and the trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between the Participants will be effected in accordance with DTC s procedures, and will be settled in same-day funds, and transfers between participants in Euroclear and Clearstream will be effected in accordance with their respective rules and operating procedures.

Cross-market transfers between the Participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC s rules on behalf of Euroclear or Clearstream, as the case may be, by their respective depositaries; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines (Brussels time) of such system. Euroclear or Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its respective depositary to take action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Note in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants and Clearstream participants may not deliver instructions directly to the depositories for Euroclear or Clearstream.

DTC has advised WPX that it will take any action permitted to be taken by a holder of notes only at the direction of one or more Participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount of the notes as to which such Participant or Participants has or have given such direction. However, if there is an Event of Default under the notes of any series, DTC reserves the right to exchange the Global Notes of such series for Certificated Notes of such series, and to distribute such notes to its Participants.

Although DTC, Euroclear and Clearstream have agreed to the foregoing procedures to facilitate transfers of interests in the Global Notes among participants in DTC, Euroclear and Clearstream, they are under no obligation to perform or to continue to perform such procedures, and may discontinue such procedures at any time. None of WPX, the trustee or any of their respective agents will have any responsibility for the performance by DTC, Euroclear or Clearstream or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note of any series is exchangeable for Certificated Notes of such series if:

(1) DTC (a) notifies WPX that it is unwilling or unable to continue as depositary for the Global Note or (b) has ceased to be a clearing agency registered under the Exchange Act and, in either case, WPX fail to appoint a successor depositary within 90 days;

(2) WPX, at its option but subject to DTC s requirements, notifies the trustee in writing that it elects to cause the issuance of the Certificated Notes; provided that in no event shall the Regulation S Global Note be exchanged for Certificated Notes prior to (a) the expiration of the Restricted Period and (b) the receipt of any certificates required under the provisions of the Indenture; or

(3) there has occurred and is continuing an Event of Default, and DTC notifies the Trustee of its decision to exchange such Global Note for Certificated Notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes upon prior written notice given to the trustee by or on behalf of DTC in accordance with the indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depositary (in accordance with its customary procedures).

Same Day Settlement and Payment

WPX will make payments in respect of the notes represented by the Global Notes (including principal, premium, if any, and interest by wire transfer of immediately available funds to the accounts specified by DTC or its nominee. WPX will make all payments of principal, premium, if any, and interest if any, with respect to Certificated Notes (i) to holders having an aggregate principal amount of $2,000,000 or less, by check mailed to such holder s registered address or (ii) to holders having an aggregate principal amount of more than $2,000,000, by check mailed to such holder s registered address or, upon application by a holder to the registrar not later than the relevant record date or in the case of payments of principal or premium, if any, not later than 15 days prior to the principal payment date, by wire transfer in immediately available funds to that holder s account within the United States (subject to surrender of the Certificated Note in the case of payments of principal or premium), which application shall remain in effect until the holder notifies the registrar to the contrary in writing. The notes represented by the Global Notes are expected to be eligible to trade in DTC s Same-Day Funds Settlement System, and any permitted secondary market trading activity in such notes will, therefore, be required by DTC to be settled in immediately available funds. WPX expect that secondary trading in any Certificated Notes will also be settled in immediately available funds.

Because of time zone differences, the securities account of a Euroclear or Clearstream participant purchasing an interest in a Global Note from a Participant will be credited, and any such crediting will be reported to the relevant Euroclear or Clearstream participant, during the securities settlement processing day (which must be a business day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised WPX that cash received in Euroclear or Clearstream as a result of sales of interests in a Global Note by or through a Euroclear or Clearstream participant to a Participant will be received with value on the settlement date of DTC but will be available in the relevant Euroclear or Clearstream cash account only as of the business day for Euroclear or Clearstream following DTC s settlement date.

Certain Definitions

Set forth below are certain defined terms used in the indenture. Reference is made to the indenture for a full disclosure of all such terms, as well as any other capitalized terms used herein for which no definition is provided.

Adjusted Treasury Rate means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that redemption date.

Affiliate of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, control, as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise. For purposes of this definition, the terms controlling, controlled by and under common control with have correlative meanings.

Board of Directors means:

(1) with respect to any corporation, the board of directors of the corporation or any authorized committee thereof;

(2) with respect to a limited liability company, the managing member or managing members or board of directors, as applicable, of such limited liability company or any authorized committee thereof;

(3) with respect to any partnership, the board of directors of the general partner of the partnership or any authorized committee thereof; and

(4) with respect to any other Person, the board or committee of such Person serving a similar function.

Business Day means each day that is not a Saturday, Sunday or other day on which banking institutions in New York, New York or another place of payment are authorized or required by law, regulation or executive order to close.

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Capital Stock means:

(1) in the case of a corporation, corporate stock;

(2) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(3) in the case of a partnership or limited liability company, partnership or membership interests (whether general or limited); and

(4) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person.

Change of Control means:

(1) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets (including Capital Stock of the Subsidiaries of WPX) of WPX and its Subsidiaries taken as a whole, to any person (as that term is used in Section 13(d)(3) of the Exchange Act);

(2) the adoption of a plan relating or the liquidation or dissolution of WPX;

(3) any person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any employee benefit plan of such person or its subsidiaries, and any person or entity acting in its capacity as trustee, agent or other fiduciary or administrator of any such plan) becomes the beneficial owner (as defined in Rules 13d-3 and 13d-5 under the Exchange Act except that a person or group shall be deemed to have beneficial ownership of all securities that such person or group has the right to acquire, whether such right is exercisable immediately or only after the passage of time (such right, an option right)), directly or indirectly, of 50% or more of the equity securities of WPX entitled to vote for members of the board of directors or equivalent governing body of WPX on a fully-diluted basis (and taking into account all such securities that such person or group has the right to acquire pursuant to any option right); or

(4) a majority of the members of the board of directors or equivalent governing body of WPX ceases to be composed of individuals (i) who were members of that board or equivalent governing body on the date the notes were issued, (ii) whose election or nomination to that board or equivalent governing body was approved by individuals referred to in clause (i) above constituting at the time of such election or nomination at least a majority of that board or equivalent governing body or (iii) whose election or nomination to that board or equivalent governing body was approved by individuals referred to in clauses (i) and (ii) above constituting at the time of such election or nomination at least a majority of that board or equivalent governing body (excluding, in the case of both clause (ii) and clause (iii), any individual whose initial nomination for, or assumption of office as, a member of that board or equivalent governing body occurs as a result of an actual or threatened solicitation of proxies or consents for the election or removal of one or more directors by any person or group other than a solicitation for the election of one or more directors by or on behalf of the board of directors).

Notwithstanding the foregoing, none of an initial public offering of WPX, the restructuring transactions described in the prospectus or any change to the board of directors or equivalent governing body of WPX in connection with either of the foregoing shall constitute a Change of Control.

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Commission means the U.S. Securities and Exchange Commission, as from time to time constituted, created under the Exchange Act or any successor agency.

Comparable Treasury Issue means the United States Treasury security or securities selected by the Quotation Agent as having an actual or interpolated maturity comparable to the remaining term of the notes of such series being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate notes of comparable maturity to the remaining term of the notes of such series.

Comparable Treasury Price means, with respect to any redemption date:

(1) the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of such Reference Treasury Dealer Quotations, or

(2) if the Quotation Agent obtains fewer than three Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

Consolidated Net Tangible Assets means at any date of determination, the total amount of assets of us and our Subsidiaries (less applicable reserves and other properly deductible items but including investments in non-consolidated persons) after deducting therefrom:

(1) all current liabilities (excluding (A) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed, and (B) current maturities of long-term debt); and

(2) the value of all goodwill, trade names, trademarks, patents, and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on our consolidated balance sheet for our most recently completed fiscal quarter, prepared in accordance with GAAP.

Domestic Subsidiary means any Subsidiary of WPX that is incorporated or organized under the laws of the United States of America, any State thereof or the District of Columbia.

Exchange Notes means the notes issued in a Registered Exchange Offer.

GAAP means generally accepted accounting principles in the United States, as such are in effect on the date of the indenture.

holder means a Person in whose name a note is registered.

Indebtedness means, with respect to any specified Person, any obligation created or assumed by such Person, whether or not contingent, for the repayment of money borrowed from others or any guarantee thereof.

International Subsidiary means each Subsidiary of WPX other than a Domestic Subsidiary.

Investment Grade Rating means a rating equal to or higher than: (i) Baa3 (or the equivalent) by Moody s; or (ii) BBB- (or the equivalent) by S&P, or, if either such entity ceases to rate a series of the notes for reasons outside of WPX s control, the equivalent investment grade credit rating from any other Rating Agency.

Joint Venture means any Person that is not a direct or indirect Subsidiary of ours in which we or any of our Subsidiaries owns any Capital Stock.

Lien means any mortgage, pledge, lien, security interest or other similar encumbrance.

Moody s means Moody s Investors Service, Inc. or, if Moody s Investors Service, Inc. shall cease rating notes having a maturity at original issue of at least one year and such ratings business shall have been transferred to a successor Person, such successor Person; provided, however, that if there is no successor Person, then Moody s shall mean any other national recognized rating agency, other than S&P, that rates notes having a maturity at original issuance of at least one year and that shall have been designated by us.

Non-Recourse Indebtedness means any Indebtedness incurred by any Joint Venture or Non-Recourse Subsidiary which does not provide for recourse against us or any Subsidiary of ours (other than a Non-Recourse Subsidiary) or any property or asset of ours or any Subsidiary of ours (other than the Capital Stock or the properties or assets of a Joint Venture or Non-Recourse Subsidiary).

Non-Recourse Subsidiary means any Subsidiary of ours (i) whose principal purpose is to incur Non-Recourse Indebtedness and/or construct, lease, own or operate the assets financed thereby, or to become a direct or indirect partner, member or other equity participant or owner in a partnership, limited partnership, limited liability partnership, corporation (including a business trust), limited liability company, unlimited liability company, joint stock company, trust, unincorporated association or joint venture created for such purpose (collectively, a *Business Entity*), (ii) who is not an obligor or otherwise bound with respect to any Indebtedness other than Non-Recourse Indebtedness, (iii) substantially all the assets of which Subsidiary or Business Entity are limited to (x) those assets being financed (or to be financed), or the operation of which is being financed (or to be financed), in whole or in part by Non-Recourse Indebtedness or (y) Capital Stock in, or Indebtedness or other obligations of, one or more other Non-Recourse Subsidiaries or Business Entities and (iv) any Subsidiary of a Non-Recourse Subsidiary; provided that such Subsidiary shall be considered to be a Non-Recourse Subsidiary only to the extent that and for so long as each of the above requirements are met.

Permitted International Debt means Indebtedness of any International Subsidiary for which neither WPX nor any Domestic Subsidiary, directly or indirectly, provides any guarantee or other credit support and which is secured, if at all, only by pledges of or liens on assets (i) held by an International Subsidiary on the date of the indenture, (ii) acquired by an International Subsidiary from a Person not constituting an Affiliate or (iii) acquired by an International Subsidiary from WPX, any Domestic Subsidiary or other Affiliate on terms that, in the good faith judgment of WPX s Board of Directors, are no less favorable to WPX or the relevant Domestic Subsidiary or other Affiliate than those that would have been obtained in a comparable transaction by WPX or such Domestic Subsidiary or other Affiliate with an unrelated Person or, if in the good faith judgment of WPX s Board of Directors, no comparable transaction is available with which to compare such transaction, such transaction is otherwise fair to WPX or the relevant Domestic Subsidiary or other Affiliate from a financial point of view.

Permitted Liens means:

(1) any Lien existing on any property at the time of the acquisition thereof and not created in contemplation of such acquisition by us or any of our Subsidiaries, whether or not assumed by us or any of our Subsidiaries;

(2) any Lien existing on any property of a Subsidiary of ours at the time it becomes a Subsidiary of ours and not created in contemplation thereof and any Lien existing on any property of any Person at the time such Person is merged or liquidated into or consolidated with us or any Subsidiary of ours and not created in contemplation thereof;

(3) purchase money and analogous Liens incurred in connection with the acquisition (including through merger, consolidation or other reorganization), development, construction, improvement, repair or replacement of property (including such Liens securing Indebtedness incurred within 12 months of the date on which such property was acquired, developed, constructed, improved, repaired or replaced); provided that all such Liens attach only to the property acquired, developed, constructed, improved, repaired or replaced and the principal amount of the Indebtedness secured by such Lien shall not exceed the gross cost of the property;

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(4) Liens on accounts receivable and related proceeds thereof arising in connection with a receivables financing and any Lien held by the purchaser of receivables derived from property or assets sold by us or any Subsidiary of ours and securing such receivables resulting from the exercise of any rights arising out of defaults on such receivables;

(5) leases constituting Liens existing on the date of the indenture or thereafter existing and any renewals or extensions thereof;

(6) any Lien securing industrial development, pollution control or similar revenue bonds;

(7) Liens existing on the date of the indenture;

(8) Liens in favor of us or any Subsidiary of ours;

(9) Liens securing Indebtedness incurred to refund, extend, refinance or otherwise replace Indebtedness (*Refinanced Indebtedness*) secured by a Lien permitted to be incurred under the indenture; provided that the principal amount of such Refinanced Indebtedness does not exceed the principal amount of Indebtedness refinanced (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses incurred therewith) at the time of refinancing;

(10) Liens on any assets or properties, or pledges of the Capital Stock, of (a) any Joint Venture owned by us or any Subsidiary of ours or (b) any Non-Recourse Subsidiary, in each case only to the extent securing Non-Recourse Indebtedness of such Joint Venture or Non-Recourse Subsidiary;

(11) Liens on the products and proceeds (including insurance, condemnation, and eminent domain proceeds) of and accessions to, and contract or other rights (including rights under insurance policies and product warranties) derivative of or relating to, property permitted by the indenture to be subject to Liens but subject to the same restrictions and limitations set forth in the indenture as to Liens on such property (including the requirement that such Liens on products, proceeds, accessions, and rights secure only obligations that such property is permitted to secure);

(12) any Liens securing Indebtedness neither assumed nor guaranteed by us or any Subsidiary of ours nor on which we or they customarily pay interest, existing upon real estate or rights in or relating to real estate (including rights-of-way and easements) acquired by us or such Subsidiary, which mortgage Liens do not materially impair the use of such property for the purposes for which it is held by us or such Subsidiary;

(13) any Lien existing or hereafter created on any office equipment, data processing equipment (including computer and computer peripheral equipment) or transportation equipment (including motor vehicles, aircraft and marine vessels);

(14) undetermined Liens and charges incidental to construction or maintenance;

(15) any Lien created or assumed by us or any Subsidiary of ours on oil, gas, coal or other mineral or timber property owned or leased by us or any Subsidiary of ours to secure loans to us or our Subsidiary, for the purpose of developing such properties;

(16)

any Lien created by us or any Subsidiary of ours on any contract (or any rights thereunder or proceeds therefrom) providing for advances by us or such Subsidiary to finance oil, natural gas, hydrocarbon or other mineral exploration or development, which Lien is created to secure Indebtedness incurred to finance such advances;

(17) any Lien granted in connection with a cash collateralization or similar arrangement to secure obligations of ours or any Subsidiary of ours to issuing banks in connection with letters of credits issued at the request of us or any Subsidiary of ours;

(18) Liens on cash deposits in the nature of a right of setoff, banker s lien, counterclaim or netting of cash amounts owed arising in the ordinary course of business on deposit accounts;

(19) Liens arising under or from farm-out or farm-in agreements, carried working interest arrangements or agreements, joint operating agreements, unitization and pooling arrangements and agreements, royalties, overriding royalties, contracts for sales of oil, gas or other mineral interests, area of mutual interest agreements, division orders, joint ventures, partnerships and similar agreements relating to the exploration or development of, or production from, oil and gas properties incurred in the ordinary course of business;

(20) Liens occurring in, arising from, or associated with Specified Escrow Arrangements;

(21) Liens securing Permitted International Debt;

(22) Liens not otherwise permitted so long as the aggregate outstanding principal amount of the Indebtedness secured thereby does not exceed $10,000,000 at any time; and

(23) Liens in respect of production payments, forward sales and similar arrangements arising in connection with Indebtedness that is payable solely out of the proceeds of the sale of oil, natural gas, hydrocarbon or other minerals produced from the properties to which such Lien attaches.

Each of the foregoing paragraphs (1) through (23) shall also be deemed to permit (i) appropriate Uniform Commercial Code and other similar filings to perfect the Liens permitted by such paragraph and (ii) Liens on the products and proceeds (including insurance, condemnation and eminent domain proceeds) of and accessions to, and contract or other rights (including rights under insurance policies and product warranties) derivative of or relating to, the property permitted to be encumbered under such paragraph, but subject to the same restrictions and limitations herein set forth as to Liens on such property (including the requirement that such Liens on products, proceeds, accessions and rights secure only the specified obligations, and in the amount, that such property is permitted to secure).

Person means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company or government or any agency or political subdivision thereof.

Quotation Agent means the Reference Treasury Dealer appointed as such agent by us.

Rating Agencies means Moody s and S&P, or if S&P or Moody s or both shall not make a rating on a series of the notes publicly available (other than as a result of voluntary action, or inaction, on the part of WPX), a nationally recognized statistical rating agency or agencies, as the case may be, selected by WPX (as certified by a resolution of WPX s Board of Directors) which shall be substituted for S&P or Moody s, or both, as the case may be.

Rating Decline means a decrease in the ratings of a series of the notes by one or more gradations (including gradations within categories as well as between rating categories) by each of the Rating Agencies on any date from the date of the public notice of an arrangement that could result in a Change of Control until the end of the 30-day period following public notice of the occurrence of the Change of Control (which 30-day period will be extended so long as the rating of such series of the notes is under publicly announced consideration for possible downgrade by either of the Rating Agencies and the other Rating Agency has either downgraded, or publicly announced that it is considering downgrading, such series of the notes). Notwithstanding the foregoing, if such series of the notes has an Investment Grade Rating by each of the Rating Agencies, then Ratings Decline means a decrease in the ratings of such series of the notes by one or more gradations (including gradations within categories as well as between rating categories) by each of the Rating Agencies such that the rating of such series of the notes by each of the Rating Agencies falls below an Investment Grade Rating on any date from the date of the public notice of an arrangement that could result in a Change of Control until the end of the 30-day period following public notice of the occurrence of the Change of Control (which 30-day period will be extended so long as the rating of such series of the notes is under publicly announced consideration for possible downgrade by either of the Rating Agencies and the other Rating Agency has either downgraded, or publicly announced that it is considering downgrading, such series of the notes).

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Reference Treasury Dealer Quotations means, with respect to any Reference Treasury Dealer and any redemption date, the average, as determined by the Quotation Agent, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Quotation Agent by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

Reference Treasury Dealers means (i) each of Barclays Capital Inc., Citigroup Global Markets Inc. and J.P. Morgan Securities LLC and their successors, unless any of such entities ceases to be a primary U.S. Government securities dealer in New York City (a *Primary Treasury Dealer*), in which case we shall substitute another Primary Treasury Dealer; and (ii) any two other Primary Treasury Dealers selected by us.

Specified Escrow Arrangements means cash deposits at one or more financial institutions for the purpose of funding any potential shortfall in the daily net cash position of WPX or any of its Subsidiaries.

Subsidiary means, with respect to any specified Person:

(1) any corporation, association or other business entity (other than a partnership or limited liability company) of which more than 50% of the total voting power of Voting Stock is at the time owned or controlled, directly or indirectly, by that Person or one or more of the other Subsidiaries of that Person (or a combination thereof); and

(2) any partnership (whether general or limited) or limited liability company (a) the sole general partner or member of which is such Person or a Subsidiary of such Person or (b) if there is more than a single general partner or member, either (x) the only managing general partners or managing members of which are such Person or one or more Subsidiaries of such Person (or any combination thereof) or (y) such Person owns or controls, directly or indirectly, a majority of the outstanding general partner interests, member interests or other Voting Stock of such partnership or limited liability company, respectively.

S&P means Standard & Poor s Ratings Service or, if Standard & Poor s Ratings Service shall cease rating notes having a maturity at original issue of at least one year and such ratings business shall have been transferred to a successor Person, such successor Person; provided, however, that if there is no successor Person, then S&P shall mean any other national recognized rating agency, other than Moody s, that rates notes having a maturity at original issuance of at least one year and that shall have been designated by us.

Voting Stock of any Person as of any date means the Capital Stock of such Person that is at the time entitled (without regard to the occurrence of any contingency) to vote in the election of the Board of Directors of such Person.

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MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

This section summarizes the material U.S. federal income tax considerations of an exchange of the outstanding notes for the exchange notes in the exchange offer and the ownership and disposition of the exchange notes. This summary does not provide a complete analysis of all potential tax considerations. The information provided below is based on the Internal Revenue Code of 1986, as amended (referred to herein as the Code), Treasury Regulations issued under the Code, judicial authority and administrative rulings and practice, all as of the date of this prospectus and all of which are subject to change, possibly on a retroactive basis. As a result, the tax considerations of owning or disposing of the exchange notes could differ from those described below. This summary deals only with exchange notes that are held as capital assets within the meaning of Section 1221 of the Code. This summary does not deal with persons in special tax situations, such as financial institutions, insurance companies, S corporations, regulated investment companies, tax-exempt investors, dealers in securities and currencies, U.S. expatriates, persons holding notes as a position in a straddle, hedge, conversion transaction, or other integrated transaction for tax purposes, or U.S. holders (as defined below) whose functional currency is not the U.S. dollar. Further, this discussion does not address the consequences under U.S. alternative minimum tax rules, U.S. federal estate or gift tax laws, the tax laws of any U.S. state or locality, any non-U.S. tax laws, or any tax laws other than income tax laws. We will not seek a ruling from the Internal Revenue Service (the IRS) with respect to any of the matters discussed herein and there can be no assurance that the IRS will not challenge one or more of the tax consequences described herein.

As used herein, the term U.S. Person means,

- an individual that is a citizen or resident of the United States,
- a corporation created or organized in or under the laws of the United States, any state or the District of Columbia,
- an estate whose income is includible in gross income for U.S. federal income tax purposes regardless of its source, or
- a trust, if (i) a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) it has a valid election in effect under applicable Treasury Regulations to be treated as a U.S. person.

As used herein, a U.S. holder is a beneficial owner of notes that is, for U.S. federal income tax purposes, a U.S. Person. As used herein, the term non-U.S. holder means a beneficial owner, other than a partnership or other entity treated as a pass-through for U.S. federal income tax purposes, of notes that is not a U.S. holder.

If a partnership, including for this purpose any entity treated as a partnership for U.S. tax purposes, is a beneficial owner of notes, the treatment of a partner in the partnership generally will depend upon the status of the partner and upon the activities of the partnership. A holder of the exchange notes that is a partnership and partners in such a partnership should consult its independent tax advisors about the U.S. federal income tax consequences of the exchange offer and of holding and disposing of the exchange notes.

Investors should consult their tax advisors concerning the tax consequences of the exchange offer and of the ownership and disposition of the exchange notes, including the tax consequences under the laws of any foreign, state, local or other taxing jurisdictions and the possible effects on investors of changes in U.S. federal or other tax laws.

Payments under Certain Events

We may be required, under certain circumstances, to pay additional amounts in redemption of the exchange notes in addition to the stated principal amount of and interest on such notes (*e.g.*, a change in control as described in Description of the Notes Change of Control). In addition, under the terms of the outstanding notes, we may have been required to pay additional interest under certain circumstances. Although the issue is not free from doubt, we have taken the position that the possibility of payment of such additional amounts in

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redemption of the exchange notes does not result in the outstanding notes or the exchange notes being treated as contingent payment debt instruments under the applicable Treasury Regulations. If additional amounts are required to be paid in redemption of the exchange notes as described above, then we intend to take the position that such amounts will be treated as additional proceeds and taxed as described below under U.S. Holders Sale, Exchange, Redemption, Retirement or Other Taxable Disposition of the Exchange Notes and Non-U.S. Holders Disposition of the Exchange Notes. These positions will be based on our determination that, as of the date of the issuance of the outstanding notes and as of the exchange offer, the possibility that additional amounts in redemption of the exchange notes will have to be paid is a remote or incidental contingency within the meaning of applicable Treasury Regulations. These positions are also based on our determination that, as of the date of the issuance of the outstanding notes, the possibility that additional interest would be paid was also remote and incidental. Our determination that this contingency is remote or incidental is binding on a holder, unless such holder explicitly discloses to the IRS on its tax return for the year during which it acquired the outstanding notes that it is taking a different position. However, our position is not binding on the IRS. If the IRS takes a contrary position to that described above, the timing and character of a holder s income and the timing of our deductions with respect to the exchange notes could be affected. Holders of the exchange notes should consult their tax advisors regarding the tax consequences of the outstanding notes or the exchange notes being treated as contingent payment debt instruments. The remainder of this discussion assumes that neither the outstanding notes nor the exchange notes will be treated as contingent payment debt instruments for U.S. federal income tax purposes.

Federal Income Tax Consequences of the Exchange Offer

The exchange of outstanding notes for exchange notes pursuant to the exchange offer will not be a taxable

transaction for U.S. federal income tax purposes. U.S. holders and non-U.S. holders will not recognize any gain

or loss as a result of such exchange and will have the same tax basis, and holding period in the exchange notes as they had in the outstanding notes immediately before the exchange.

Federal Income Tax Consequences of the Ownership and Disposition of the Exchange Notes to U.S. Holders

Stated Interest

Interest on an exchange note will be includable by a U.S. holder as interest income at the time it accrues or is received in accordance with such holder s method of accounting for U.S. federal income tax purposes and will be ordinary income.

Amortizable Premium

A U.S. holder who acquires an exchange note for an amount in excess of stated principal amount will be considered to have purchased the note with amortizable bond premium equal to the excess. A U.S. holder may elect to amortize that premium under a constant yield method over the remaining term of the exchange note (which will result in a corresponding decrease in the adjusted tax basis of the note) and may offset interest otherwise required to be included in respect of the exchange note during any taxable year by the amortized amount of such premium for the taxable year. However, if the exchange note may be redeemed at a price that is greater than its stated principal amount, special rules would apply that could result in a reduction in the amortization of the bond premium or a deferral of the amortization of a portion of the bond premium until later in the term of the note. Any election to amortize bond premium applies to all taxable debt obligations then owned and thereafter acquired by the U.S. holder and may be revoked only with the consent of the IRS. U.S. holders that acquire an exchange note with bond premium should consult their tax advisors regarding the manner in which such premium is calculated and the election to amortize bond premium over the life of the instrument.

Sale, Exchange, Redemption, Retirement or Other Taxable Disposition of the Exchange Notes

Upon the disposition of an exchange note by sale, exchange, redemption, retirement or other taxable disposition, a U.S. holder will generally recognize gain or loss equal to the difference between (i) the amount realized on the disposition (other than amounts attributable to accrued but unpaid interest, which will be taxed as such) and (ii) the U.S. holder s tax basis in the exchange note. A U.S. holder s tax basis in an exchange note generally will equal the cost of such note. Except as discussed under the caption Market Discount, a U.S. holder s gain or loss will generally constitute capital gain or loss and will be long-term capital gain or loss if the U.S. holder has held such note for longer than one year. The deductibility of capital losses is subject to certain limitations. Net long-term capital gain recognized by a non-corporate U.S. holder is generally taxed at preferential rates.

Market Discount

An exchange note that is acquired for an amount that is less than its principal amount by more than a de minimis amount (generally 0.25% of the principal amount multiplied by the number of remaining whole years to maturity), will be treated as having market discount equal to such difference. Unless the U.S. holder elects to include such market discount in income as it accrues, a U.S. holder will be required to treat any principal payment on, and any gain on the sale, exchange, retirement or other disposition (including a gift) of, an exchange note as ordinary income to the extent of any accrued market discount that has not previously been included in income. In general, market discount on the exchange note will accrue ratably over the remaining term of the exchange notes or, at the election of the U.S. holder, under a constant yield method. In addition, a U.S. holder could be required to defer the deduction of all or a portion of the interest paid on any indebtedness incurred or continued to purchase or carry an exchange note unless the U.S. holder elects to include market discount in income currently. Such an election applies to all debt instruments held by a taxpayer and may not be revoked without the consent of the IRS.

Medicare Tax

Certain U.S. holders that are individuals, estates or trusts will be required to pay an additional 3.8% Medicare tax on, among other things, interest on, and capital gains from the sale or other disposition of the exchange notes for taxable years beginning after December 31, 2012.

Backup Withholding and Information Reporting

In general, a U.S. holder of an exchange note will be subject to backup withholding at the applicable tax rate with respect to cash payments in respect of interest or the gross proceeds from the dispositions of such note, unless the holder (i) is an entity that is exempt from backup withholding (generally including tax-exempt organizations and certain qualified nominees) and, when required, provides appropriate documentation to that effect, (ii) provides us or our paying agent with the social security number or other taxpayer identification number (TIN) within a reasonable time after a request therefor, certifies that the TIN provided is correct and that the holder has not been notified by the IRS that it is subject to backup withholding due to underreporting of interest or dividends, and otherwise complies with applicable requirements of the backup withholding rules. In addition, such payments to U.S. holders that are not exempt entities will generally be subject to information reporting requirements. A U.S. holder who does not provide us or our paying agent with the correct TIN may be subject to penalties imposed by the IRS. The amount of any backup withholding from a payment to a U.S. holder will be allowed as a credit against such holder s U.S. federal income tax liability and may entitle such holder to a refund, provided that the required information is timely furnished to the IRS. We or our paying agent will report to the holders and the IRS the amount of any reportable payments and any amounts withheld with respect to the notes as required by the Code and applicable Treasury Regulations.

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Federal Income Tax Consequences of the Ownership and Disposition of the Exchange Notes to Non-U.S. Holders

The following discussion applies to non-U.S. holders. Special rules may apply if a non-U.S. holder is a controlled foreign corporation, foreign personal holding company, or a corporation that accumulates earnings to avoid U.S. federal income tax.

Interest

Subject to the discussion of backup withholding below, interest income of a non-U.S. holder will not be subject to U.S. federal income tax or withholding tax, provided

- the interest is not income that is effectively connected with a United States trade or business conducted by the non-U.S. holder (ECI);
- the non-U.S. holder does not actually or constructively (pursuant to the rules of Section 871(h)(3)(C) of the Code) own 10% or more of the total combined voting power of all classes of our stock that are entitled to vote;
- the non-U.S. holder is not a controlled foreign corporation related to us actually or constructively through the stock ownership rules under Section 864(d)(4) of the Code;
- the non-U.S. holder is not a bank that is receiving the interest on an extension of credit made pursuant to a loan agreement entered into in the ordinary course of business; and
- the beneficial owner satisfies the certification requirements set forth in Section 871(h) or 881(c), as applicable, of the Code and the Treasury regulations issued thereunder by giving us or our paying agent an appropriate IRS Form W-8 (or a suitable substitute or successor form or such other form as the IRS may prescribe) that has been properly completed and duly executed establishing its status as a non-U.S. Person or by other means prescribed by the Secretary of the Treasury.

If any of these conditions are not met, interest on the exchange notes paid to a non-U.S. holder will generally be subject to U.S. federal income tax and withholding at a 30% rate unless (a) an applicable income tax treaty reduces or eliminates such tax, and the non-U.S. holder claims the benefit of that treaty by providing an appropriate IRS Form W-8 (or a suitable substitute or successor form or such other form as the IRS may prescribe) that has been properly completed and duly executed, or (b) the interest is ECI and the non-U.S. holder complies with applicable certification requirements by providing an appropriate IRS Form W-8 (or a suitable substitute or successor form or such other form as the IRS may prescribe) that has been properly completed and duly executed.

If the interest on the exchange notes is ECI, the non-U.S. holder will be required to pay U.S. federal income tax on that interest on a net income basis (and the 30% withholding tax described above will not apply, provided the appropriate statement is provided to us or our paying agent) generally in the same manner as a U.S. holder. If a non-U.S. holder is eligible for the benefits of any income tax treaty between the United States and its country of residence, any interest income that is ECI will be subject to U.S. federal income tax in the manner specified by the treaty and will generally be subject to U.S. federal income tax only if such income is attributable to a permanent establishment or a fixed base maintained by the non-U.S. holder in the United States, provided that the non-U.S. holder claims the benefit of the treaty by providing an appropriate IRS Form W-8 (or a suitable substitute or successor form or such other form as the IRS may prescribe) that has been properly completed and duly executed. In addition, interest received by a corporate non-U.S. holder that is ECI may also, under certain circumstances, be subject to an additional branch profits tax at a 30% rate, or, if applicable, a lower treaty rate.

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Disposition of the Exchange Notes

A non-U.S. holder will generally not be subject to U.S. federal income tax on gain (other than any amount allocable to accrued and unpaid interest, which is taxable as interest and may be subject to the rules discussed above in Federal Income Tax Consequences of the Ownership of the Exchange Notes to Non-U.S. Holders Interest) realized on a sale, redemption or other disposition of the exchange notes unless

- the gain is ECI or

- in the case of a non-U.S. holder who is a nonresident alien individual and holds the exchange note as a capital asset, such holder is present in the United States for 183 or more days in the taxable year and certain other requirements are met.

If a non-U.S. holder falls under the first of these exceptions, the holder will be taxed on the net gain derived from the disposition under the graduated U.S. federal income tax rates that are applicable to U.S. Persons, unless reduced by treaty. If the non-U.S. holder is a foreign corporation, it may also be subject to the branch profits tax described above, unless reduced by treaty. Even though the ECI will be subject to U.S. federal income tax, and possibly subject to the branch profits tax, it will not be subject to withholding if the non-U.S. holder delivers an appropriate IRS Form W-8 (or a suitable substitute or successor form or such other form as the IRS may prescribe) that has been properly completed and duly executed to us or our agent.

If an individual non-U.S. holder falls under the second of these exceptions, the holder generally will be subject to U.S. federal income tax at a rate of 30% on the amount by which the gain derived from the disposition from sources within the United States exceeds such holder s capital losses allocable to sources within the United States for the taxable year of the sale.

A non-U.S. holder s ability to claim a loss on the disposition of the exchange notes will be subject to substantial limitations. Non-U.S. holders should consult their tax advisors regarding the tax consequences of disposing of the exchange notes at a loss.

Backup Withholding and Information Reporting

Backup withholding and information reporting will not apply to payments of principal or interest on the exchange notes by us or our paying agent if a holder certifies its status as a non-U.S. holder under penalties of perjury or otherwise establishes an exemption (provided that neither we nor our paying agent has actual knowledge that it is a U.S. Person or that the conditions of any other exemptions are not in fact satisfied). The payment of the proceeds of the disposition of the exchange notes to or through the United States office of a United States or foreign broker will be subject to information reporting and backup withholding unless the non-U.S. holder provides the certification described above or otherwise establishes an exemption. The proceeds of a disposition effected outside the United States by a holder of the exchange notes to or through a foreign office of a broker generally will not be subject to backup withholding or information reporting. However, if that broker is, for United States tax purposes, a U.S. Person, a controlled foreign corporation, a foreign person 50% or more of whose gross income from all sources for certain periods is effectively connected with a trade or business in the United States, or a foreign partnership that is engaged in the conduct of a trade or business in the United States or that has one or more partners that are U.S. Persons who in the aggregate hold more than 50% of the income or capital interests in the partnership, information reporting requirements will apply unless that broker has documentary evidence in its files of such holder s status as a non-U.S. holder and has no actual knowledge to the contrary or unless such holder otherwise establishes an exemption. Any amounts withheld from a payment to a holder under the backup withholding rules will be allowed as a credit against such holder s U.S. federal income tax liability and may entitle it to a refund, provided it timely furnishes the required information to the IRS. We or our paying agent will report to the holders and the IRS the amount of any reportable payments and any amounts withheld with respect to the exchange notes as required by the Code and applicable Treasury Regulations.

The U.S. federal tax discussion set forth above as to both U.S. holders and non-U.S. holders is included for general information only and may not be applicable depending upon a holder s particular situation. Holders should consult their tax advisors with respect to the tax consequences to them of the exchange offer and the ownership and disposition of the notes, including the tax consequences under state, local, foreign and other tax laws and the possible effects of changes in U.S. federal or other tax laws.

PLAN OF DISTRIBUTION

Each broker-dealer that receives exchange notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange notes received in exchange for outstanding notes where such outstanding notes were acquired as a result of market-making activities or other trading activities. We have agreed that for a period of 180 days after the expiration of the exchange offer, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale.

We will not receive any proceeds from any sale of exchange notes by brokers-dealers. Exchange notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the exchange notes or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer and/or the purchasers of any such exchange notes. Any broker-dealer that resells exchange notes that were received by it for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such exchange notes may be deemed to be an underwriter within the meaning of the Securities Act and any profit on any such resale of exchange notes and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act.

We have agreed to pay all expenses incident to the exchange offer (including the expenses of one counsel for the holders of the notes), other than commissions or concessions of any brokers or dealers and will indemnify the holders of the notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

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LEGAL MATTERS

Certain matters with respect to the issuance of the notes offered hereby will be passed upon for us by Gibson, Dunn & Crutcher LLP.

EXPERTS

Ernst & Young LLP, our independent registered public accounting firm, has audited our consolidated financial statements and schedule at December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, as set forth in their report included in this prospectus. We have included our consolidated 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 99 percent of our year-end 2011 U.S. proved reserves estimates included in this prospectus were audited by Netherland, Sewell & Associates, Inc.

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INDEX TO FINANCIAL STATEMENTS, SUPPLEMENTARY DATA AND SCHEDULE

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of WPX Energy, Inc.

We have audited the accompanying consolidated balance sheet of WPX Energy, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audit also included the financial statement schedule listed in the Index at Item 21.(b). These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 consolidated financial position of WPX Energy, Inc. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 28, 2012

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WPX Energy, Inc.

Consolidated Statement of Operations

	Years Ended December 31,		
	2011	2010	2009
	(Millions, except per share amounts)		
Revenues:			
Product revenues, including sales to Williams:			
Natural gas sales	$ 1,795	$ 1,812	$ 1,929
Natural gas liquid sales	408	285	139
Oil and condensate sales	315	128	97
Total product revenues, including sales to Williams	2,518	2,225	2,165
Gas management, including sales to Williams	1,428	1,742	1,456
Hedge ineffectiveness and mark to market gains and losses	29	27	18
Other	13	40	42
Total revenues	3,988	4,034	3,681
Costs and expenses:			
Lease and facility operating, including expenses with Williams	295	286	263
Gathering, processing and transportation, including expenses with Williams	499	326	273
Taxes other than income	140	125	93
Gas management, including charges for unutilized pipeline capacity	1,473	1,771	1,495
Exploration	134	73	54
Depreciation, depletion and amortization	949	875	887
Impairment of producing properties and costs of acquired unproved reserves	547	678	15
Goodwill impairment		1,003	
General and administrative, including expenses with Williams	285	253	251
Other net	1	(19)	33
Total costs and expenses	4,323	5,371	3,364
Operating income (loss)	(335)	(1,337)	317
Interest expense, including expenses with Williams	(117)	(124)	(100)
Interest capitalized	9	16	18
Investment income and other	26	21	8
Income (loss) from continuing operations before income taxes	(417)	(1,424)	243
Provision (benefit) for income taxes	(145)	(149)	96
Income (loss) from continuing operations	(272)	(1,275)	147
Loss from discontinued operations	(20)	(8)	(7)
Net income (loss)	(292)	(1,283)	140
Less: Net income attributable to noncontrolling interests	10	8	6
Net income (loss) attributable to WPX Energy	$ (302)	$ (1,291)	$ 134
Amounts attributable to WPX Energy, Inc.:			
Basic and diluted earnings (loss) per common share (see Note 6):			
Income (loss) from continuing operations	$ (1.43)	$ (6.51)	$ 0.71
Loss from discontinued operations	(0.10)	(0.04)	(0.03)

Net income (loss)	$ (1.53)	$ (6.55)	$ 0.68
Weighted-average shares (millions)	197.1	197.1	197.1

See accompanying notes.

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WPX Energy, Inc.

Consolidated Balance Sheet

	December 31, 2011	December 31, 2010
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$ 526	$ 37
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $13 and $16 as of December 31, 2011 and 2010, respectively	447	362
Williams	62	60
Derivative assets	506	400
Inventories	74	77
Other	59	22
Total current assets	1,674	958
Investments	125	105
Properties and equipment, net (successful efforts method of accounting)	8,476	8,449
Derivative assets	10	173
Other noncurrent assets	147	161
Total assets	$ 10,432	$ 9,846
Liabilities and Equity		
Current liabilities:		
Accounts payable:		
Trade	643	451
Williams	59	64
Accrued and other current liabilities	186	158
Deferred income taxes	116	87
Notes payable to Williams		2,261
Derivative liabilities	152	146
Total current liabilities	1,156	3,167
Deferred income taxes	1,556	1,645
Long-term debt	1,503	
Derivative liabilities	7	143
Asset retirement obligations	296	282
Other noncurrent liabilities	155	125
Contingent liabilities and commitments *(Note 12)*		
Equity:		
Stockholders equity:		
Preferred stock (100 million shares authorized at $0.01 par value; no shares issued)		
Common stock (2 billion shares authorized at $0.01 par value; 197 million shares issued at December 31, 2011)	2	
Additional paid-in-capital	5,457	
Williams net investment		4,244
Accumulated other comprehensive income	219	168
Total stockholders equity	5,678	4,412
Noncontrolling interests in consolidated subsidiaries	81	72

Total equity	5,759	4,484
Total liabilities and equity	$ 10,432	$ 9,846

See accompanying notes.

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WPX Energy, Inc.

Consolidated Statement of Changes in Equity

	WPX Energy, Inc., Stockholders						
	Common Stock	Capital in Excess of Par Value	Williams Net Investment	Accumulated Other Comprehensive Income (Loss)*	Total Stockholders Equity	Noncontrolling Interest**	Total
	(Dollars in millions)						
Balance at December 31, 2008	$	$	$ 5,136	$ 298	$ 5,434	$ 59	$ 5,493
Comprehensive income:							
Net income			134		134	6	140
Other comprehensive income:							
Change in fair value of cash flow hedges (net of $97 of income tax)				169	169		169
Net reclassifications into earnings of net cash flow hedge gains(net of $226 income tax provision)				(395)	(395)		(395)
Total other comprehensive income							(226)
Total comprehensive income							(86)
Net transfers with Williams			(16)		(16)		(16)
Dividends to noncontrolling interests						(1)	(1)
Balance at December 31, 2009			5,254	72	5,326	64	5,390
Comprehensive income:							
Net income			(1,291)		(1,291)	8	(1,283)
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 gain (net of $129 income tax provision)				(225)	(225)		(225)
Total other comprehensive loss							96
Total comprehensive loss							(1,187)
Cash proceeds in excess of historical book value related to assets sold to a Williams affiliate			244		244		244
Net transfers with Williams			37		37		37
Dividends to noncontrolling interests							
Balance at December 31, 2010			4,244	168	4,412	72	4,484
Comprehensive income:							
Net loss			(302)		(302)	10	(292)
Other comprehensive income:							
Change in fair value of net cash flow hedges (net of $151 of income tax)				262	262		262
Net reclassifications into earnings of cash flow hedge gains (net of $120 income tax provision)				(211)	(211)		(211)
Total other comprehensive income							51

Total comprehensive loss							(241)
Contribution of Notes Payable to Williams (Note 4)			2,420		2,420		2,420
Allocation of alternative minimum tax credit (see Note 11)			98		98		98
Net transfers with Williams			(25)		(25)		(25)
Distribution to Williams a portion of note proceeds			(981)		(981)		(981)
Recapitalization upon contribution by Williams	2	5,452	(5,454)				
Dividends to noncontrolling interests						(1)	(1)
Stock based compensation, net of tax benefit		5			5		5
Balance at December 31, 2011	$ 2	$ 5,457	$	$ 219	$ 5,678	$ 81	$ 5,759

* Accumulated other comprehensive income (loss) is comprised primarily of unrealized gains relating to natural gas hedges totaling $221 million (net of $128 million for income taxes), $169 million (net of $97 million for income taxes) and $74 million (net of $42 million for income taxes) as of December 31, 2011, 2010 and 2009, 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, Inc.

Consolidated Statement of Cash Flows

	Years Ended December 31,		
	2011	2010	2009
		(Millions)	
Operating Activities			
Net income (loss)	$ (292)	$ (1,283)	$ 140
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	951	882	894
Deferred income tax provision (benefit)	(176)	(166)	108
Provision for impairment of goodwill and properties and equipment (including certain exploration expenses)	694	1,734	38
Provision for loss on cost-based investment			11
Amortization of stock-based awards	5		
(Gain) loss on sales of other assets	(1)	(22)	1
Cash provided (used) by operating assets and liabilities:			
Accounts receivable and payable Williams	(10)	21	(72)
Accounts receivable trade	(90)	7	103
Other current assets	(11)	19	(17)
Inventories	3	(16)	24
Margin deposits and customer margin deposit payable	(18)	(1)	4
Accounts payable trade	131	(54)	(17)
Accrued and other current liabilities	10	(62)	(109)
Changes in current and noncurrent derivative assets and liabilities	8	(45)	38
Other, including changes in other noncurrent assets and liabilities	2	42	35
Net cash provided by operating activities	1,206	1,056	1,181
Investing Activities			
Capital expenditures*	(1,572)	(1,856)	(1,434)
Purchase of business		(949)	
Proceeds from sales of assets	15	493	
Purchases of investments	(12)	(7)	(1)
Other	13	(18)	
Net cash used in investing activities	(1,556)	(2,337)	(1,435)
Financing Activities			
Proceeds from long term debt	1,502		
Payments for debt issuance costs	(30)		
Net increase in notes payable to Williams	159	1,045	270
Net changes in Williams net investment, including a $981 distribution in 2011	(777)	241	(16)
Other	(15)	(2)	2
Net cash provided by financing activities	839	1,284	256
Net increase in cash and cash equivalents	489	3	2
Cash and cash equivalents at beginning of period	37	34	32
Cash and cash equivalents at end of period	$ 526	$ 37	$ 34
	$ (1,641)	$ (1,891)	$ (1,291)

* Increase to properties and equipment			
Changes in related accounts payable	69	35	(143)
Capital expenditures	$ (1,572)	$ (1,856)	$ (1,434)

See accompanying notes.

WPX Energy, Inc.

Notes to Consolidated Financial Statements

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company are located in the United States and South America and are organized into Domestic and International reportable segments.

Domestic 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. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related derivatives coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco Oil and Gas International Inc. (Apco , NASDAQ listed: APAGF), an oil and gas exploration and production company with concessions primarily in Argentina.

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as WPX or the Company , previously comprised substantially all of the exploration and production reportable segment of The Williams Companies, Inc. In these notes, WPX Energy, Inc. is at times referred to in the first person as WPX , we , us or our . The Williams Companies, Inc. and its affiliates, including Williams Partners L.P. (WPZ) are at times referred to collectively as Williams.

On February 16, 2011, Williams announced that its Board of Directors had approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. As a result, WPX Energy, Inc. was 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 WPX Energy Holdings, LLC (formerly Williams Production Holdings, LLC) and WPX Energy Production, LLC (formerly Williams Production Company, LLC), as well as all ongoing operations of WPX Energy Marketing, LLC (formerly Williams Gas Marketing, Inc.). Additionally, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its approximate 69 percent ownership interest in Apco in October 2011. We refer to the collective contributions described herein as the Contribution .

On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011 of WPX common stock to Williams stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date. See Note 4 for further discussion of agreements entered at the time of the spin-off, including a separation and distribution agreement, a transition services agreement, an employee matters agreement and a tax sharing agreement, among others.

Basis of Presentation

These financial statements are prepared on a consolidated basis. Prior to the Contribution, the financial statements were 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.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 prior to the Contribution among the various entities that comprise the Company, Williams net investment in the Company, excluding notes payable to Williams, has been shown as Williams net investment within stockholder s equity in the consolidated financial statements. In connection with the Contribution, we have reflected the amounts previously presented as owner s net investment in excess of the par value of our common stock as additional paid-in capital. Transactions with Williams other operating businesses, which generally settle monthly, are shown as accounts receivable Williams or accounts payable Williams (see Note 4). Other transactions between the Company and Williams which are not part of the notes payable to Williams have been identified in the Consolidated Statement of Equity as net transfers with Williams (see Note 4).

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, are expected to be eliminated from our ongoing operations, and we do not expect to 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 consolidated financial statements and notes include the results of operations of Williams former power business most of which was disposed in 2007 as discontinued operations. See Note 12 for a discussion of contingencies related to this discontinued power business.

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations.

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our wholly and majority-owned subsidiaries and investments. Companies in which we 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 consolidated 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;

- Valuations of derivatives;

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Hedge accounting correlations and probability;

Estimation of oil and natural gas reserves;

Assessments of litigation-related contingencies.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Our cash and cash equivalents balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Restricted cash

Restricted cash of our Domestic segment primarily consists of approximately $19 million in both 2011 and 2010 related to escrow accounts established as part of the settlement agreement with certain California utilities and is included in other noncurrent assets. Included in the separation and distribution agreement with Williams are indemnifications requiring us to pay to Williams any net asset (or receive any net liability) that result upon ultimate resolution of these matters. See Note 12. Additionally, our International segment holds approximately $8 million of restricted cash in 2011 associated with various letters of credit that is also classified in other noncurrent 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 of tubular goods and production equipment for future transfer to wells of $40 million in 2011 and $46 million in 2010. Additionally, we have natural gas in storage of $34 million in 2011 and $31 million in 2010 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 recognized lower of cost or market writedowns on natural gas in storage of $10 million in 2011, $2 million in 2010 and $7 million in 2009.

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.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 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 Consolidated 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 basis 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 total 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.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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.

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.

Contingent liabilities

Owing to the nature of our business, we are routinely subject to various lawsuits, claims and other proceedings. We recognize a liability in our consolidated financial statements when we determine that it is probable that a loss has been incurred and the amount can be reasonably estimated. If we determine that a loss is probable but lack information on which to reasonably estimate a loss, if any, or if we determine that a loss is only reasonably possible, we do not recognize a liability. We disclose the nature of loss contingencies that are potentially material but for which no liability has been recognized.

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

As a result of significant declines in forward natural gas prices during 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 and no longer have any goodwill recorded on the consolidated balance sheet related to our domestic operations (see Note 16).

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.

Cash flows from revolving credit facilities

Proceeds and payments related to any borrowings under our credit facilities are reflected in the financing activities of the Consolidated Statement of Cash Flows on a gross basis.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 Consolidated 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

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.

For many of our existing commodity derivatives, we have also designated a hedging relationship. 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.

Certain gains and losses on derivative instruments included in the Consolidated 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;

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

- 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.

Product revenues

Revenues for sales of natural gas, natural gas liquids, and oil and condensate 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, 2011 and 2010 was insignificant. Additionally, natural gas revenues include hedge gains realized on production sold of $327 million in 2011, $333 million in 2010 and $615 million in 2009.

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 $37 million in 2011, $48 million in 2010 and $21 million in 2009.

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 until June 30, 2011 was the rate charged to us by Williams through June 30, 2011, at which time our intercompany note with Williams was forgiven (see Note 4). We did not capitalize interest for the period from July 1, 2011 to mid November 2011. During November 2011, we began using the weighted average rate of our long-term notes payable which were issued in November 2011 (see Note 10).

Income taxes

Through the effective date of the spin-off, the Company s domestic operations were 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 for the Company and its

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected benefit to the Company could not be determined until the date of deconsolidation. 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 recovered or settled.

Effective with the spin-off, certain state and federal tax attributes (primarily alternative minimum tax credits) have been allocated between Williams and the Company. Although the final allocation of these tax attributes cannot be determined until the consolidated tax returns for tax year 2011 are complete, which is expected in the third quarter of 2012, an estimate of the tax attributes allocated to the Company has been recorded in the 2011 financial statements as part of the Contribution.

Employee stock-based compensation

Until spin-off, certain employees providing direct service to us participated in Williams common-stock-based awards plans. The plans provided for Williams common-stock-based awards to both employees and Williams non-management directors. The plans permitted the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards were granted for no consideration other than prior and future services or based on certain financial performance targets.

Until spin-off, Williams charged us for compensation expense related to stock-based compensation awards granted to our direct employees. Stock based compensation was also a component of allocated amounts charged to us by Williams for general and administrative personnel providing services on our behalf.

In preparation for the spin-off, Williams Compensation Committee determined that all outstanding Williams equity-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 (Pre-2006 Options) would convert into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options were converted into options covering both Williams and WPX common stock. The number of shares underlying each award and, with respect to options, the per share exercise price of each such award has been adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of such 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 can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options 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.

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.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. Diluted earnings (loss) per common share includes any dilutive effect of stock options and nonvested restricted stock units, unless otherwise noted. The impact of our stock issuance has been given effect to all periods presented. (see Note 6).

Accounting Standards Issued But Not Yet Adopted

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. ASU 2011-5 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 Consolidated Statement of Operations and reports other comprehensive income in the Consolidated Statement of Equity. In December 2011, The FASB issued Accounting Standards Update No. 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). ASU 2011-12 defers the effective date for only the presentation requirements related to reclassifications in ASU 2011-5. During this deferral period, ASU 2011-12 states that we should continue to report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before ASU 2011-05. All other requirements in ASU 2011-05 are not affected by ASU 2011-12, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. Both ASU s are effective beginning the first quarter of 2012, with retrospective application to prior periods. We will apply the new guidance for both ASUs beginning in 2012.

Note 2. Restatement of Prior Periods

We have determined that we did not appropriately provide for deferred federal income taxes on the outside basis differences of a foreign equity investee for the years ended December 31, 2010 and 2009. As a result, our provision (benefit) for income taxes was understated and our net income from continuing operations was overstated by $1 million and $2 million for the years ended December 31, 2010 and 2009, respectively, our deferred income tax liability was understated by $16 million at December 31, 2010 and our net equity was overstated by $16 million, $15 million and $13 million at December 31, 2010, 2009 and 2008, respectively. This restatement also adjusted downward our earnings per share attributable to WPX Energy, Inc. by $.01 in each of the years ended December 31, 2010 and 2009. 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 financial statements. We have adjusted our previously reported results for the years ended December 31, 2010 and 2009 for these amounts.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	2011	2010 (Millions)	2009
Revenues	$ 13	$ 16	$ 17
Loss from discontinued operations before impairments, gain on sale and income taxes	$ (3)	$ (13)	$ (11)
Impairments	(29)		
Benefit for income taxes	12	5	4
Loss from discontinued operations	$ (20)	$ (8)	$ (7)

Impairments in 2011 reflect write-downs to estimates of fair value less costs to sell the assets of our Arkoma Basin operations that were classified as held for sale as of December 31, 2011. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, utilized a probability-weighted discounted cash flow analysis that was based on internal cash flow models.

The assets of our discontinued operations are significantly less than one percent of our total assets as of December 31, 2011 and 2010 and are reported in other assets and other noncurrent assets, respectively on our Consolidated Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

Note 4. Transactions with Williams

During the fourth quarter of 2011, the Contribution and recapitalization of the Company was completed, whereby common stock held by Williams converted into approximately 197 million shares of WPX common stock. We also entered into agreements with Williams in connection with our separation from Williams. These agreements include:

- A Separation and Distribution agreement for, among other things, the separation from Williams and the distribution of WPX common stock, the distribution of a portion of the net proceeds from the debt financing as well as agreements between us and Williams, including those relating to indemnification;

- A tax sharing agreement, providing for, among other things, the allocation between Williams and WPX of federal, state, local and foreign tax liabilities for periods prior to the distribution and in some instances for periods after the distribution;

- An employee matters agreement discussed below; and

- A transition services agreement discussed below.

Personnel and related services

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 the Williams benefit plans and terminated their personnel services agreements with Williams payroll companies. Simultaneously, two new administrative service 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 in June 2011 had any employees. Through December 30, 2011, these service entities employed all personnel that provided services to the Company and remained owned and controlled by Williams.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

In connection with the spin-off, we entered into an Employee Matters Agreement with Williams that set forth our agreements with Williams as to certain employment, compensation and benefits matters. The Employee Matters Agreement provides 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 provided 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 transferred to us from Williams in connection with the spinoff through the contribution of two newly established service entities that employees of Williams were moved to prior to the spinoff. The Employee Matters Agreement provides 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 ceased active participation in those plans as of January 1, 2012. At December 31, 2011, certain paid time off accruals approximating $13 million were transferred from Williams to us and are reflected in accrued liabilities. Additionally, while we have been charged for these costs, Williams remains responsible for any bonus amounts to be paid to our employees for the 2011 year which are currently estimated to be $19 million.

All outstanding Williams equity awards (other than stock options granted prior to January 1, 2006) held by our employees as of the spin-off were converted into WPX equity awards, issued pursuant to a plan that we established. See Note 14. 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 were converted into options to acquire both WPX common stock and Williams common stock, in the same proportion as the number of shares of WPX common stock that each holder of Williams common stock received in the spin-off. The conversion maintained the same intrinsic value as the applicable Williams equity award as of the date of the conversion.

Until the spin-off, Williams charged us for the payroll and benefit costs associated with operations employees (referred to as direct employees) and carried 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 was charged to us through affiliate billings and reflected in lease and facility operating and general and administrative within costs and expenses in the accompanying Consolidated Statement of Operations.

In addition, Williams charged us for certain employees of Williams who provide general and administrative services on our behalf (referred to as indirect employees). These charges were either directly identifiable or allocated to our operations. Direct charges included goods and services provided by Williams at our request. Allocated general corporate costs were 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 was reflected in general and administrative expense in the accompanying Consolidated 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 have entered into a transition services agreement with Williams under which Williams will provide to us, upon our request and on an interim basis, various corporate support services subsequent to the spin-off. These services consist generally of the services that have been provided to us on an intercompany basis prior to the spin-off. These services relate to;

- treasury services;
- finance and accounting;
- tax;

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

- 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 transition services agreement, Williams will provide certain services for up to one year after the spin-off. 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. The transition services agreement may be terminated by either us or Williams upon 60 days notice after the spin-off. 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.

Other arrangements with Williams or its affiliates

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

- Sales to WPZ and another Williams subsidiary of natural gas procured by WPX Energy Marketing 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

- Pipeline transportation for both our oil and gas sales and gas management activities which includes commitments totaling $401 million (see Note 12 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. 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 Consolidated 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, 2011, 2010 and 2009. We have signed an agreement with Williams under which these contracts will be assigned to them in the near term.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 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 were under common control at that time, no gain was recognized on this transaction in the Consolidated 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 Consolidated 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 were, 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 Consolidated 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 have been presented in the Consolidated Statement of Operations as continuing operations for periods prior to the sale. In March 2011, the 1.8 million WPZ units and related tax basis were distributed via dividend to Williams.

We have managed 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 $11 million, $10 million and $9 million for the years ended December 31, 2011, 2010 and 2009, respectively, and are included in gas management revenues. We have signed an agreement with WPZ under which these contracts will be assigned to them in the near term.

WPZ periodically entered into derivative contracts with us to hedge their forecasted NGL sales and natural gas purchases. We entered into offsetting derivative contracts with third parties at equivalent pricing and volumes. These contracts are included in derivative assets and liabilities on the Consolidated Balance Sheet at December 31, 2010. No contracts existed at December 31, 2011.

Prior to December 1, 2011 we participated in Williams centralized approach to cash management and the financing of its businesses. 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. Through fourth-quarter 2011, an additional $162 million was cancelled and reflected as an increase in owner s net investment. The notes reflected interest based on Williams weighted average cost of debt and such interest was added monthly to the note principle. The interest rate for the notes payable to Williams was 8.08%, 8.08% and 8.01% at June 30, 2011, December 31, 2010 and 2009, respectively.

Under Williams cash-management system, certain cash accounts reflected negative balances to the extent checks written had not been presented for payment. These negative amounts represented obligations and were reclassified to accounts payable-affiliate. Accounts payable-affiliate includes approximately $38 million of these negative balances at December 31, 2010. On December 1, 2011, we initiated our own cash management system as we began self-funding our operations. To the extent that certain cash accounts reflect negative balances, that obligation is reflected within our external accounts payable.

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 million per year.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Below is a summary of the transactions with Williams or its affiliates discussed above:

	2011	2010	2009
		(Millions)	
Product revenues sales of NGLs to WPZ	$ 258	$ 277	$ 116
Gas management revenues sales of natural gas for fuel and shrink to WPZ and another Williams subsidiary	586	509	431
Lease and facility operating expenses from Williams-direct employee salary and benefit costs	21	23	23
Gathering, processing and transportation expense from services with WPZ:			
Gathering and processing	298	163	72
Transportation	44	25	28
General and administrative from Williams:			
Direct employee salary and benefit costs	111	102	100
Charges for general and administrative services	62	58	60
Allocated general corporate costs	62	64	63
Other	16	12	13
Interest expense on notes payable to Williams	96	119	92

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 and other assets and liabilities with Williams and its affiliates:

	December 31, 2011	December 31, 2010
	(Millions)	
Current:		
Accounts receivable:		
Due from WPZ and another Williams subsidiary	$ 62	$ 60
Other noncurrent assets Due from Williams	$ 11	$
Accounts payable:		
Due to WPZ	$ 35	$ 12
Due to Williams for cash overdraft		38
Due to Williams for accrued payroll and benefits	10	14
Due to Williams for administrative expenses	14	
	$ 59	$ 64
Noncurrent liability to Williams	$ 48	$

Note 5. Investment Income and Other

Investment income

	Years Ended December 31,		
	2011	2010	2009
		(Millions)	
Equity earnings	$ 24	$ 20	$ 18
Impairment of cost-based investment			(11)
Other	2	1	1
Total investment income and other	$ 26	$ 21	$ 8

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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

	December 31, 2011	December 31, 2010
	(Millions)	
Petrolera Entre Lomas S.A. 40.8%	$ 90	$ 82
Other	35	23
	$ 125	$ 105

Petrolera Entre Lomas S.A. operates several development concessions in South America. Other is comprised of investments in miscellaneous gas gathering interests in the United States.

Dividends and distributions received from companies accounted for by the equity method were $17 million in 2011, $19 million in 2010 and $9 million in 2009.

Note 6. Earnings (Loss) Per Common Share from Continuing Operations

	Years Ended December 31, 2011	2010	2009
	(Millions, except per-share amounts)		
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$ (282)	$ (1,283)	$ 141
Basic weighted-average shares	197.1	197.1	197.1
Diluted weighted-average shares	197.1	197.1	197.1
Earnings (loss) per common share from continuing operations:			
Basic	$ (1.43)	$ (6.51)	$ 0.71
Diluted	$ (1.43)	$ (6.51)	$ 0.71

On December 31, 2011, 197.1 million shares of our common stock were distributed to Williams shareholders in conjunction with our spin-off. For comparative purposes, and to provide a more meaningful calculation for weighted average shares, we have assumed this amount of common stock to be outstanding as of the beginning of each period presented in the calculation of basic weighted average shares.

For 2011 approximately 2.9 million weighted-average nonvested restricted stock units and 1.2 million weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive to our loss from continuing operations attributable to WPX Energy, Inc. For 2010 and 2009 these amounts are not given retrospective effect to the calculation.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Note 7. 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. These significant adjustments are associated with our domestic operations.

	Years Ended December 31, 2011	2010 (Millions)	2009
Goodwill impairment	$	$ 1,003	$
Impairment of producing properties and costs of acquired unproved reserves *	547	678	15
Penalties from early release of drilling rigs included in other (income) expense net			32
(Gain) loss on sales of other assets	(1)	(22)	1

* Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.

As part of our assessment for impairments primarily resulting from declining forward natural gas prices during the fourth quarter 2011, we recorded a $276 million impairment of proved producing oil and gas properties in the Powder River basin and a $180 million impairment in Barnett Shale (see Note 16). Additionally, we recorded a $91 million impairment of our capitalized cost of acquired unproved reserves in the Powder River.

As a result of significant declines in forward natural gas prices during 2010, we performed an 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 16).

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 16).

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 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 4). Also in 2010, we exchanged undeveloped leasehold acreage in different areas with a third party resulting in a $7 million gain.

The following presents a summary of exploration expenses:

	Years Ended December 31, 2011	2010 (Millions)	2009
Geologic and geophysical costs	$ 18	$ 22	$ 33
Dry hole costs	13	17	11
Unproved leasehold property impairment, amortization and expiration	103	34	10

Total exploration expense	$ 134	$ 73	$ 54

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Dry hole costs in 2011 include an $11 million dry hole expense in connection with a Marcellus Shale well in Columbia County, Pennsylvania, while 2010 and 2009 reflect dry hole expense associated primarily with wells in the 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 in Pennsylvania.

Note 8. Properties and Equipment

Properties and equipment is carried at cost and consists of the following:

	Estimated Useful Life (a) (Years)	December 31, 2011	December 31, 2010
		(Millions)	
Proved properties	(b)	$ 9,985	$ 9,822
Unproved properties	(c)	1,555	1,893
Gathering, processing and other facilities	15-25	181	119
Construction in progress	(c)	692	603
Other	3-25	99	127
Total properties and equipment, at cost		12,512	12,564
Accumulated depreciation, depletion and amortization		(4,036)	(4,115)
Properties and equipment net		$ 8,476	$ 8,449

(a) Estimated useful lives are presented as of December 31, 2011.
(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 held approximately 85,800 net acres on the Fort Berthold Indian Reservation in the Williston Basin of North Dakota. Approximately 85% of the acreage was 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 years ended December 31, 2010 and 2009.

As discussed in Note 4 in 2010, 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.

Construction in progress includes $113 million in 2011 and $142 million in 2010 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.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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.

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 2011 and 2010 is presented below.

	2011	2010
	(Millions)	
Balance, January 1	$ 285	$ 242
Liabilities incurred during the period	23	43
Liabilities settled during the period	(2)	(2)
Liabilities associated with assets sold		(22)
Estimate revisions	(24)	3
Accretion expense *	20	21
Balance, December 31	$ 302	$ 285
Amount reflected as current	$ 6	$ 3

* Accretion expense is included in lease and facility operating expense on the Consolidated Statement of Operations.
Estimate revisions in 2011 are primarily associated with changes in anticipated well lives and plug and abandonment costs.

Note 9. Accrued and other current liabilities

Accrued and other current liabilities

	December 31,	
	2011	2010
	(Millions)	
Taxes other than income taxes	$ 79	$ 76
Customer margin deposits	7	25
Accrued interest	13	1
Compensation and benefit related accruals	13	
Other, including other loss contingencies	74	56
	$ 186	$ 158

Prior to the spin-off, employee compensation and benefit accruals were obligations of Williams with the expense related to compensation allocated to us through affiliate charges.

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Note 10. Debt and Banking Arrangements

In connection with our separation from Williams, we issued $1.5 billion face value Senior Notes as follows:

	December 31, 2011	December 31, 2010
	(Millions)	
5.250% Senior Notes due 2017	$ 400	$
6.000% Senior Notes due 2022	1,100	
Other	3	
	$ 1,503	$

Senior Notes

The Notes were issued under an indenture between us and The Bank of New York Mellon Trust Company, N.A., as trustee. The net proceeds from the offering of the Notes were approximately $1.481 billion after deducting the initial purchasers discounts and our offering expenses. We retained $500 million of the net proceeds from the issuance of the Notes and distributed the remainder of the net proceeds from the issuance of the Notes, approximately $981 million, to Williams in connection with the Contribution.

Optional Redemption. We have the option, prior to maturity, in the case of the 2017 notes, and prior to October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes), in the case of the 2022 notes, to redeem all or a portion of the Notes of the applicable series at any time at a redemption price equal to the greater of (i) 100% of their principal amount and (ii) the discounted present value of 100% of their principal amount and remaining scheduled interest payments, in either case plus accrued and unpaid interest to the redemption date. We also have the option at any time on or after October 15, 2021, to redeem the 2022 notes, in whole or in part, at a redemption price equal to 100% of their principal amount, plus accrued and unpaid interest thereon to the redemption date.

Change of Control. If we experience a change of control (as defined in the indenture governing the Notes) accompanied by a rating decline with respect to a series of Notes, we must offer to repurchase the Notes of such series at 101% of their principal amount, plus accrued and unpaid interest.

Covenants. The terms of the indenture restrict our ability and the ability of our subsidiaries to incur additional indebtedness secured by liens and to effect a consolidation, merger or sale of substantially all our assets. The indenture also requires us to file with the trustee and the SEC certain documents and reports within certain time limits set forth in the indenture. However, these limitations and requirements will be subject to a number of important qualifications and exceptions. The indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity.

Events of Default. Each of the following is an Event of Default under the indenture with respect to the Notes of any series:

(1) a default in the payment of interest on the Notes when due that continues for 30 days;

(2) a default in the payment of the principal of or any premium, if any, on the Notes when due at their stated maturity, upon redemption, or otherwise;

(3) failure by us to duly observe or perform any other of the covenants or agreements (other than those described in clause (1) or (2) above) in the indenture, which failure continues for a period of 60 days, or, in the case of the reporting covenant under the indenture, which failure continues for a period of 90 days, after

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

the date on which written notice of such failure has been given to us by the trustee; provided, however, that if such failure is not capable of cure within such 60-day or 90-day period, as the case may be, such 60-day or 90-day period, as the case may be, will be automatically extended by an additional 60 days so long as (i) such failure is subject to cure and (ii) we are using commercially reasonable efforts to cure such failure; and

(4) certain events of bankruptcy, insolvency or reorganization described in the indenture.

Registration Rights Agreement. As part of the new issuance, we entered into a registration rights agreement whereby we agree to offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and to use commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offer within 30 business days after such effective date. We are required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If we fail to fulfill these obligations, additional interest will accrue on the affected securities until we have successfully registered the securities.

Credit Facility Agreement

During 2011 we entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility Agreement). Under the terms of the Credit Facility Agreement and subject to certain requirements, we 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 may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. At December 31, 2011 there was no outstanding balance under the Credit Facility Agreement.

The Credit Facility Agreement became effective on November 1, 2011. Also, on November 1, 2011 we terminated our existing unsecured credit agreement which had served to reduce margin requirements and transaction fees related to hedging activities. All outstanding hedges under the terminated agreement were transferred to new agreements with various financial institutions that also participate in the new credit facility. We nor the participating financial institutions are required to provide collateral support related to hedging activities under the new agreements.

Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at the option of WPX Energy: (1) a fluctuating base rate equal to the Alternate Base Rate plus the Applicable Rate, or (2) a periodic fixed rate equal to LIBOR plus the Applicable Rate. The Alternate Base Rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. The Applicable Rate changes depending on which interest rate WPX selects and WPX s credit rating. Additionally, WPX Energy will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility Agreement.

Under the Credit Facility Agreement, prior to the occurrence of the Investment Grade Date (as defined below), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (each as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. Net present value 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 (such cash flows adjusted to reflect the impact of hedges, our lenders commodity price forecasts, and, if necessary, including only a portion of our reserves that are not proved developed producing reserves). Additionally, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. Beginning December 31, 2011, each of the above ratios will be tested at the end of each fiscal quarter. We were in compliance with our debt covenant ratios as of December 31, 2011. Investment Grade Date means the first date on which our long-term

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 our subsidiaries to incur indebtedness, make investments, loans or advances and enter into certain hedging agreements; our ability to merge or consolidate with any person or sell all or substantially all of our 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 our 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.

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 us occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of any loans outstanding under the Credit Facility Agreement at the time, in addition to the exercise of other rights and remedies available.

Letters of Credit

In addition to the Notes and Credit Facility Agreement, WPX has executed three bilateral, uncommitted letter of credit (LC) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility Agreement. At December 31, 2011 a total of $292 million in letters of credit have been issued.

Other

Apco executed a loan agreement with a financial institution for a $10 million bank line of credit. Borrowings under this facility are unsecured and bear interest at six-month LIBOR plus three percent per annum plus a one percent arrangement fee per borrowing and a commitment fee for the unused portion of the loan amount. The funds can be borrowed during a one-year period ending in March 2012, and principal amounts will be repaid in semi-annual installments from each borrowing date after a two and a half year grace period. This debt agreement contains covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, purchase or sell assets outside the ordinary course of business, and incur additional debt. As of December 31, 2011, we have borrowed $2 million under this banking agreement. Aggregate minimum maturities of this long-term debt are $1 million each for 2013 and 2014.

Note 11. Income Taxes

Through the effective date of the spin-off, the Company s domestic operations were 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 for the Company and its consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected impact to the Company could not be determined until the date of deconsolidation.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Effective with the spin-off, Williams and the Company entered into a tax sharing agreement which governs the respective rights, responsibilities and obligations of each company, for tax periods prior to the spin-off, 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 and other matters regarding taxes.

The provision (benefit) for income taxes from continuing operations includes:

	Years Ended December 31,		
	2011	2010	2009
		(Millions)	
Provision (benefit):			
Current:			
Federal	$ 5	$ 7	$ (17)
State	4	1	(1)
Foreign	10	11	9
	19	19	(9)
Deferred:			
Federal	(161)	(158)	99
State	(3)	(10)	6
	(164)	(168)	105
Total provision (benefit)	$ (145)	$ (149)	$ 96

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,		
	2011	2010	2009
		(Millions)	
Provision (benefit) at statutory rate	$ (146)	$ (498)	$ 85
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(8)	(6)	3
Effective state income tax rate change (net of federal benefit)	9		
Foreign operations net		4	6
Goodwill impairment		351	
Other net			2
Provision (benefit) for income taxes	$ (145)	$ (149)	$ 96

Income (loss) from continuing operations before income taxes includes $40 million, $36 million and $21 million of foreign income in 2011, 2010 and 2009, respectively.

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Notes to Consolidated Financial Statements (continued)

Significant components of deferred tax liabilities and deferred tax assets are as follows:

	December 31, 2011	December 31, 2010
	(Millions)	
Deferred tax liabilities:		
Properties and equipment	$ 1,779	$ 1,739
Derivatives, net	137	110
Total deferred tax liabilities	1,916	1,849
Deferred tax assets:		
Accrued liabilities and other	146	117
Alternative minimum tax credits (a)	98	
Loss carry-overs	16	22
Total deferred tax assets	260	139
Less: valuation allowance	16	22
Total net deferred tax assets	244	117
Net deferred tax liabilities	$ 1,672	$ 1,732

(a) In connection with the spin-off from Williams effective December 31, 2011, alternative minimum tax credits were able to be estimated and allocated between Williams and the Company. This resulted in the allocation to the Company of $98 million with a corresponding increase to additional paid-in capital. Any subsequent adjustments of the alternative minimum tax credit allocation with Williams will be recorded in the provision for the period in which the change occurs.

As of December 31, 2011, the Company has approximately $290 million of state net operating loss carryovers of which approximately 75 percent expire after 2020.

The valuation allowance at December 31, 2011 and 2010 serves to reduce the recognized tax assets 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, 2011 and 2010.

Undistributed earnings of certain consolidated foreign subsidiaries excluding amounts related to foreign equity investments at December 31, 2011, totaled approximately $66 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 in accordance with Williams intercompany tax allocation procedure. Cash payments for domestic income taxes (net of receipts) were $10 million, $5 million and ($13) million in 2011, 2010 and 2009, respectively. Additionally, payments made directly to international taxing authorities were $10 million, $8 million and $4 million in 2011, 2010 and 2009, respectively.

The Company s policy is to recognize related interest and penalties as a component of income tax expense. The amounts accrued for interest and penalties are insignificant.

Pursuant to our tax sharing agreement with Williams, we will remain responsible for the tax from audit adjustments related to our business for periods prior to the spin-off. During the first quarter of 2011, Williams

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finalized settlements with the IRS for 1997 through 2008. The statute of limitations for most states expires one year after expiration of the IRS statute. Income tax returns for our foreign operations, primarily in Argentina, are open to audit for the 2004 to 2011 tax years.

As of December 31, 2011, the amount of unrecognized tax benefits is insignificant. 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.

Note 12. 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 proceeds 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 for certification resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim is 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 entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate litigating the second reserved claim in 2012. 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.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint alleges failure to pay royalty on hydrocarbons including drip condensate, fraud and misstatement of value of gas and affiliated sales, breach of duty to market hydrocarbons, violation of the New Mexico Oil and Gas Proceeds Payment Act, bad faith breach of contract and unjust enrichment. Plaintiffs seek monetary damages and a declaratory judgment enjoining activities relating to production and payments and future reporting. This matter has been removed to the United States District Court for New Mexico. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

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Notes to Consolidated Financial Statements (continued)

Other producers have been in litigation with a federal regulatory agency and discussions with 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 those matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. 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 though such guidelines are expected in the future. However, the timing of any such guidance is uncertain. 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. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. 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. From January 2004 through December 2011, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $72 million.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that we have 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. At this time, we do not have a sufficient basis to calculate an estimated range of exposure related to this claim.

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, one hour nitrogen dioxide emission limits, and hydraulic fracturing and water standards. 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

In connection with the Separation and Distribution Agreement, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us, and we are obligated to pay Williams any net proceeds realized from, the pending or threatened litigation described below relating to the 2000-2001 California energy crisis and the reporting of certain natural gas-related information to trade publications.

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.

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Notes to Consolidated Financial Statements (continued)

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, seeking unspecified amounts 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. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

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. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. Because of the uncertainty around 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 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, 2011, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, 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 connection with the separation from Williams, we have agreed to indemnify and hold Williams harmless from any losses resulting from the operation of our business or arising out of liabilities assumed by us. Similarly, Williams has agreed to indemnify and hold us harmless from any losses resulting from the operation of its business or arising out of liabilities assumed by it.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Summary

As of December 31, 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. 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.

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 former affiliates systems, resulting in a total of $401 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 December 31, 2011 are as follows:

	(Millions)
2012	$ 215
2013	211
2014	177
2015	167
2016	149
Thereafter	489
Total	$ 1,408

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 $780 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 anticipated to begin in the first quarter of 2012. 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 Consolidated Financial Statements (continued)

Future minimum annual rentals under noncancelable operating leases as of December 31, 2011, are payable as follows:

	(Millions)
2012	$ 67
2013	76
2014	67
2015	32
2016	9
Thereafter	36
Total	$ 287

Total rent expense, excluding month-to-month rentals, was $16 million, $13 million and $22 million in 2011, 2010 and 2009, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting.

Note 13. Employee Benefit Plans

Prior to spin-off

Through the spin-off date, certain benefit costs associated with direct employees who support our operations are determined based on a specific employee basis and were charged to us by Williams as described below. These pension and post retirement benefit costs included amounts associated with vested participants who are no longer employees. As described in Note 4 Williams also charged us for the allocated cost of certain indirect employees of Williams who provided general and administrative services on our behalf. Williams included 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 that supported our operations.

For the periods presented, we were not the plan sponsor for these plans. Accordingly, our Consolidated 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 provides pension benefits for its eligible employees. Pension expense charged to us by Williams for 2011, 2010 and 2009 totaled $8 million, $7 million and $7 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. Other postretirement benefit expense charged to us by Williams for 2011, 2010, and 2009 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 has charged us compensation expense of $4 million, $5 million and $5 million in 2011, 2010 and 2009, respectively, for Williams matching contributions to this plan.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Subsequent to spin-off

On January 1, 2012, several new plans became effective for us including a defined contribution plan. WPX matches dollar-for-dollar up to the first 6 percent of eligible pay per period. Employees also receive a non-matching annual employer contribution of equal to 8 percent of eligible pay if they are age 40 or older and 6 percent of eligible pay if they are under age 40.

Note 14. Stock-Based Compensation

Certain of our direct employees participated 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 eligible direct employees participated 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.

Through the date of spin-off we were 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. 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).

Williams Compensation Committee determined that all outstanding Williams stock-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 (the Pre-2006 Options), be converted into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options (whether held by our employees or other Williams employees) converted into options for both Williams and WPX common stock following the spin-off, in the same ratio as is used in the distribution of WPX common stock to holders of Williams common stock. The number of shares underlying each such award (including the Pre-2006 Options) and, with respect to options (including the Pre-2006 Options), the per share exercise price of each award was adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of each award.

Total stock-based compensation expense included in general and administrative expense for the years ended December 31, 2011, 2010 and 2009 was $18 million, $14 million, and $13 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2011 was $24 million. This amount is comprised of $2 million related to stock options and $22 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

WPX Energy, Inc. 2011 Incentive Plan

Subsequent to the spin-off, we have an equity incentive plan and an employee stock purchase plan. The 2011 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units and other stock-based awards. The number of shares of common stock authorized for issuance pursuant to all awards granted under the 2011 Incentive Plan is 11,000,000 shares. The 2011 Incentive Plan will be administered by either the full Board of Directors or a committee as designated by the Board of Directors. Our employees, officers and non-employee directors are eligible to receive awards under the 2011 Incentive Plan.

The employee stock purchase plan allows domestic employees the option to purchase WPX common stock at a 15 percent discount through after-tax payroll deductions. The purchase price of the stock is the lower of

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

either the first or last day of the biannual offering periods, followed with the 15 percent discount. The maximum number of shares that shall be made available under the purchase plan is 1,000,000, subject to adjustment for stock splits and similar events.

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 fair 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.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2011.

	WPX Plan			Direct employees participation in Williams Plan		
Stock Options	**Options (Millions)**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value (Millions)**	**Options (Millions)**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value (Millions)**
Outstanding at December 31, 2010		$	$	1.6	$ 18.23	$ 13
Granted		$		.2	$ 29.73	
Exercised		$		(.4)	$ 13.52	
Expired		$		(.1)	$ 34.66	
Conversion of direct employee options	2.0	$ 12.81		(1.3)	$ 21.08	
Conversion of other options(1)	2.2	$ 10.16			$	
Outstanding at December 31, 2011	4.2	$ 11.41	$ 29		$	
Exercisable at December 31, 2011	3.0	$ 10.92	$ 22			

(1) Includes approximately 962 thousand shares held by Williams employees at a weighted average price of $7.07 per share.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $7 million, $2 million, and $0.2 million, respectively.

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Notes to Consolidated Financial Statements (continued)

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2011.

	WPX Plan					
	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)**
$ 1.26 to $6.02	1.4	$ 5.19	4.6	1.2	$ 5.00	4.1
$ 6.49 to $11.75	1.1	$ 11.21	5.7	0.7	$ 10.93	4.4
$12.00 to $15.67	0.7	$ 14.41	4.8	0.7	$ 14.41	4.8
$16.46 to $20.97	1.0	$ 18.17	7.8	0.4	$ 20.23	6.2
Total	4.2	$ 11.41	5.7	3.0	$ 10.92	4.6

The estimated fair value at date of conversion for WPX awards and the date of grant of options for Williams common stock granted in each respective year, using the Black-Scholes option pricing model, is as follows:

	WPX Plan 2011	Williams Plan 2011	2010	2009
Weighted-average or grant date fair value of options granted	$	$ 7.71	$ 7.02	$ 5.60
Weighted-average conversion date fair value options granted	$ 8.48			
Weighted-average assumptions:				
Dividend yield	%	3.6%	2.6%	1.6%
Volatility	45%	34.6%	39.0%	60.8%
Risk-free interest rate	0.377%	2.84%	3.0%	2.3%
Expected life (years)	2.8	6.5	6.5	6.5

For the WPX Plan the weighted average fair value is a component of the intrinsic value calculation at spin-off and is not necessarily indicative of the fair value of future WPX grants. The expected volatility yield is based on the historical volatility of comparable peer group stocks. The risk free rate interest rate is based on the U.S. Treasury Constant Maturity rates as of the modification date. The expected life of the options is based over the remaining option term.

For the Williams Plan, 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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Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2011.

Restricted Stock Units	WPX Plan Shares (Millions)	WPX Plan Weighted-Average Fair Value*	Direct employees participation in Williams Plan Shares (Millions)	Direct employees participation in Williams Plan Weighted-Average Fair Value*
Nonvested at December 31, 2010		$	1.8	$ 16.93
Granted		$	.5	$ 27.74
Forfeited		$	(.1)	$ 18.20
Cancelled		$	(.1)	$ 35.47
Vested		$	(.3)	$ 32.75
Conversion of direct employee restricted units	3.3	$ 9.74	(1.8)	$ 17.59
Conversion of indirect employee restricted units	1.3	$ 9.54		
Nonvested at December 31, 2011	4.6	$ 9.69		$

* Performance-based shares are primarily valued using a valuation pricing model. However, certain of these shares were valued using the end-of-period market price until certification that the performance objectives were completed or a value of zero once it was determined that it was unlikely that performance objectives would be met. All other shares are valued at the grant-date market price, less dividends projected to be paid over the vesting period.

Other restricted stock unit information

	Williams Plan 2011	Williams Plan 2010	Williams Plan 2009
Weighted-average grant date fair value of Williams restricted stock units granted during the year, per share	$ 27.74	$ 20.00	$ 9.71
Total fair value of restricted stock units vested during the year ($ s in millions)	$ 10	$ 9	$ 8

Performance-based shares granted represent 13 percent of nonvested restricted stock units outstanding at December 31, 2011. These grants may be earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 15. Stockholders Equity

Common Stock

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. 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. No dividends were declared or paid as of December 31, 2011. No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

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Notes to Consolidated Financial Statements (continued)

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. Rights and privileges associated with shares of preferred stock are subject to authorization by our Board of Directors and may differ from those of any and all other series at any time outstanding.

Note 16. Fair Value Measurements

Fair value is the amount received from the sale of 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 measurements primarily consist 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 indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 measurements primarily consist 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.

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 measurements consist 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.

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Notes to Consolidated Financial Statements (continued)

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.

	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$ 55	$ 454	$ 7	$ 516	$ 97	$ 474	$ 2	$ 573
Energy derivative liabilities	$ 41	$ 112	$ 6	$ 159	$ 78	$ 210	$ 1	$ 289

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 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 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 December 31, 2011, consist primarily of natural gas index transactions that are used to manage our physical requirements.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 years ended December 31, 2011 or 2010. During the period ended March 31, 2011, certain NGL swaps that originated during the first quarter of 2011 were transferred from Level 3 to Level 2. Prior to March 31, 2011, these swaps were considered Level 3 due to a lack of observable third-party market quotes. Due to an increase in exchange-traded transactions and greater visibility from OTC trading, we transferred these instruments to Level 2. 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 table presents 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

	Years ended December 31,		
	2011	2010	2009
	Net Energy Derivatives	Net Energy Derivatives (Millions)	Net Energy Derivatives
Beginning balance	$ 1	$ 1	$ 506
Realized and unrealized gains (losses):			
Included in income (loss) from continuing operations	15	1	476
Included in other comprehensive income (loss)			(329)
Purchases, issuances, and settlements	(12)	(1)	(479)
Transfers out of Level 3	(3)		(173)
Ending balance	$ 1	$ 1	$ 1
Unrealized gains included in income (loss) from continuing operations relating to instruments still held at December 31	$ 1	$	$

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statement of Operations.

For the year ending December 31, 2011, the entire $12 million reduction to level 3 fair value measurements are settlements.

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.

	Total losses for the years ended December 31,		
	2011	2010 (Millions)	2009
Impairments:			
Goodwill (see Note 7)	$	$ 1,003(b)	$

Producing properties and costs of acquired unproved reserves (see Note 7)	547(a)	678(c)	15(d)
Cost-based investment (see Note 5)			11(e)
	$ 547	$ 1,681	$ 26

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

(a) Due to significant declines in forward natural gas prices, 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 including potential disposition proceeds. Significant judgments and assumptions in these assessments 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 annual assessment identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded the following impairment charges. Fair value measured for these properties at December 31, 2011, was estimated to be approximately $798 million.

$276 million of impairment charge related to natural gas-producing properties in Powder River. Significant assumptions in valuing these properties included proved reserves quantities of more than 352 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.81 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

$180 million of 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 235 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.24 per Mcfe for natural gas (adjusted for locational differences and contractual arrangements), natural gas liquids and oil, and an after-tax discount rate of 11 percent. Additionally, the weighted average price is net of deductions for gathering and processing.

$91 million of the impairment charge related to acquired unproved reserves in Powder River. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.

(b) 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

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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.

(c) As of September 30, 2010, 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 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 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. Additionally, the weighted average price is net of deductions for gathering and processing.

$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.

(d) Fair value of costs acquired reserves in the Barnett Shale measured at December 31, 2009, was $22 million. Significant assumptions 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.

(e) 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.

Note 17. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

We use the following methods and assumptions for financial instruments that require fair value disclosure.

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated 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 Consolidated Balance Sheet approximate fair value given the short-term status of the instruments.

Long-term debt: The fair value of our debt is determined on market rates and the prices of similar securities with similar terms and credit ratings.

Energy derivatives: Energy derivatives include futures, forwards, swaps and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 16 for a discussion of valuation of energy derivatives.

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Notes to Consolidated Financial Statements (continued)

Carrying amounts and fair values of our financial instruments were as follows:

	December 31,			
	2011		2010	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
	(Millions)			
Cash and cash equivalents	$ 526	$ 526	$ 37	$ 37
Restricted cash (current and noncurrent)	29	29	24	24
Other	(7)	(7)	(25)	(25)
Long-term debt (1)	1,502	1,523		
Net energy derivatives:				
Energy commodity cash flow hedges	347	347	266	266
Other energy derivatives	10	10	18	18

(1) Excludes capital leases.

For the year ended December 31, 2010 our note payable to Williams had a carrying amount of $2,261, which approximated fair value.

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 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.

We produce, buy and sell natural gas and oil 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 and oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and 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. 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.

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Notes to Consolidated Financial Statements (continued)

The following table sets forth the derivative volumes designated as hedges of production volumes as of December 31, 2011:

Commodity	Period	Contract Type	Location	Notional Volume (BBtu)	Weighted Average Price ($/MMBtu)
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	Northeast	52,460	$ 5.58
Natural Gas	2013	Location Swaps	Northeast	1,800	$ 6.48

Commodity	Period	Contract Type	Location	Notional Volume (MBbl)	Weighted Average Price ($/Bbl)
Crude Oil	2012	Business Day Avg Swaps	Midcon	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. Derivatives for transportation and 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 providing services to third parties and affiliated entities. 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, 2011. Natural gas is presented in millions of British Thermal Units (MMBtu) and crude oil is presented in barrels. The volumes for options represent zero-cost collars and present one side of the short position. These 2012 options were executed to reduce exposure to a decrease in revenues from fluctuations in crude oil market prices. The floor and ceiling prices associated with these collars are $85 per barrel and $106.30 per barrel, respectively, and realize by December 2012. Despite being economic hedges, we did not designate these contracts in a hedge relationship for accounting purposes. All of the Central hub risk realizes by March 31, 2013 and 91% 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 December 31, 2011.

Derivative Notional Volumes	Unit of Measure	Central Hub Risk (a)	Basis Risk (b)	Index Risk (c)	Option Risk (e)
Not Designated as Hedging Instruments					
Risk Management	MMBtu	(14,396,621)	(15,570,621)	(35,487,182)	
Other	MMBtu	(7,500)	(7,102,500)		
Risk Management (d)	Barrels	(730,000)			(732,000)

(a) includes physical and financial derivative transactions that settle against the Henry Hub price;
(b) includes physical and financial derivative transactions priced off the difference in value between the Central Hub and another specific delivery point;

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

(c) includes physical derivative transactions at an unknown future price, including purchases of 81,679,958 MMBtu primarily on behalf of WPZ and sales of 117,167,110 MMBtu.
(d) includes financial derivatives entered into to hedge our crude oil exposure that were not designated in a hedging relationship at December 31, 2011.
(e) includes all fixed price options or combination of options that set a floor and/or ceiling for the transaction price of a commodity.

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 Consolidated 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,			
	2011		2010	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 360	$ 13	$ 288	$ 22
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	93	92	186	187
All other	63	54	99	80
Total derivatives not designated as hedging instruments	156	146	285	267
Total derivatives	$ 516	$ 159	$ 573	$ 289

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,		
	2011	2010	Classification
	(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$ 413	$ 505	AOCI
Net gain reclassified from *accumulated other comprehensive income (loss)* into income (effective portion) (1)	$ 331	$ 354	Revenues
Gain recognized in income (ineffective portion)	$	$ 9	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.

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Notes to Consolidated Financial Statements (continued)

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Years Ended December 31, 2011	2010
	(Millions)	
Gas management revenues	$ 30	$ 47
Gas management expenses		28
Net gain	$ 30	$ 19

The cash flow impact of our derivative activities is presented in the Consolidated 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 agreements with certain banks related to economic hedging activities. We are not required to provide collateral support for net derivative liability positions under these agreements.

As of December 31, 2011, we had collateral totaling $18 million posted to derivative counterparties to support the aggregate fair value of our net $37 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 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 $19 million and $29 million at December 31, 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 December 31, 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 December 31, 2011, $219 million of net gains (net of income tax provision of $127 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, 2011. Due to the volatile nature of commodity prices and changes in the creditworthiness of

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 Williams), net of allowances, by product or service as of December 31:

	2011	2010
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services	$ 286	$ 272
Joint interest owners	150	83
Other	11	7
Total	$ 447	$ 362

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, 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 2011, 2010 and 2009, we did not incur any significant losses due to counterparty bankruptcy filings.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

The gross credit exposure from our derivative contracts as of December 31, 2011, is summarized as follows.

Counterparty Type	Investment Grade*	Total
	(Millions)	
Gas and electric utilities and integrated oil and gas companies	$ 2	$ 2
Energy marketers and traders		50
Financial institutions	410	464
	$ 412	516
Credit reserves		
Gross credit exposure from derivatives		$ 516

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, 2011, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade*	Total
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders		4
Financial institutions	374	388
	$ 376	394
Credit reserves		
Net credit exposure from derivatives		$ 394

* 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 97 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are counterparty positions hedging our production of energy commodities, representing 88 percent of our net credit exposure from derivatives. Under our new marginless hedging agreements with key banks, we nor the participating financial institutions are required to provide collateral support related to hedging activities.

At December 31, 2011, we hold collateral support, which may include cash or letters of credit, of $2 million related to our other derivative positions.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Revenues

During 2011 and 2010, BP Energy Company, a domestic segment customer, accounted for 11% and 13% of our consolidated revenues, respectively. During 2009, there were no customers for which our sales exceeded 10 percent of our consolidated 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.

Note 18. Segment Disclosures

Our reporting segments are Domestic and International. (See Note 1.)

Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and International maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

Performance Measurement

We evaluate performance based upon segment revenues and segment operating income (loss). The accounting policies of the segments are the same as those described in Note 1. There are no intersegment sales between Domestic and International. Costs historically allocated from Williams were not allocated by us to our International segment.

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Notes to Consolidated Financial Statements (continued)

The following tables reflect the reconciliation of segment revenues and segment operating income (loss) to revenues and operating income (loss) as reported in the Consolidated Statement of Operations. Long-lived assets are comprised of gross property, plant and equipment and long-term investments.

For the year ended December 31, 2011	Domestic	International (Millions)	Total
Total revenues	$ 3,878	$ 110	$ 3,988
Costs and expenses:			
Lease and facility operating	$ 268	$ 27	$ 295
Gathering, processing and transportation	499		499
Taxes other than income	119	21	140
Gas management, including charges for unutilized pipeline capacity	1,473		1,473
Exploration	131	3	134
Depreciation, depletion and amortization	927	22	949
Impairment of producing properties and costs of acquired unproved reserves	547		547
General and administrative	273	12	285
Other net	(2)	3	1
Total costs and expenses	$ 4,235	$ 88	$ 4,323
Operating income (loss)	$ (357)	$ 22	$ (335)
Interest expense, including affiliate	(117)		(117)
Interest capitalized	9		9
Investment income and other	6	20	26
Income (loss) from continuing operation before income taxes	$ (459)	$ 42	$ (417)
Other financial information:			
Net capital expenditures	$ 1,531	$ 41	$ 1,572
Total assets	$ 10,144	$ 288	$ 10,432
Long-lived assets	$ 12,284	$ 354	$ 12,638

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Notes to Consolidated Financial Statements (continued)

For the year ended December 31, 2010	Domestic	International (Millions)	Total
Total revenues	$ 3,945	$ 89	$ 4,034
Costs and expenses:			
Lease and facility operating	$ 267	$ 19	$ 286
Gathering, processing and transportation	326		326
Taxes other than income	109	16	125
Gas management, including charges for unutilized pipeline capacity	1,771		1,771
Exploration	67	6	73
Depreciation, depletion and amortization	858	17	875
Impairment of producing properties and costs of acquired unproved reserves	678		678
Goodwill impairment	1,003		1,003
General and administrative	244	9	253
Other net	(19)		(19)
Total costs and expenses	$ 5,304	$ 67	$ 5,371
Operating income (loss)	$ (1,359)	$ 22	$ (1,337)
Interest expense, including affiliate	(124)		(124)
Interest capitalized	16		16
Investment income and other	4	17	21
Income (loss) from continuing operation before income taxes	$ (1,463)	$ 39	$ (1,424)
Other financial information:			
Net capital expenditures	$ 1,821	$ 35	$ 1,856
Total assets	$ 9,590	$ 256	$ 9,846
Long lived assets	$ 12,363	$ 306	$ 12,669

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WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

For the year ended December 31, 2009	Domestic	International (Millions)	Total
Total revenues	$ 3,603	$ 78	$ 3,681
Costs and expenses:			
Lease and facility operating	$ 247	$ 16	$ 263
Gathering, processing and transportation	273		273
Taxes other than income	80	13	93
Gas management, including charges for unutilized pipeline capacity	1,495		1,495
Exploration	53	1	54
Depreciation, depletion and amortization	870	17	887
Impairment of producing properties and costs of acquired unproved reserves	15		15
General and administrative	242	9	251
Other net	32	1	33
Total costs and expenses	$ 3,307	$ 57	$ 3,364
Operating income	$ 296	$ 21	$ 317
Interest expense, including affiliate	(100)		(100)
Interest capitalized	18		18
Investment income and other	5	3	8
Income from continuing operation before income taxes	$ 219	$ 24	$ 243
Other financial information:			
Net capital expenditures	$ 1,409	$ 25	$ 1,434
Total assets	$ 10,323	$ 230	$ 10,553
Long lived assets	$ 11,014	$ 270	$ 11,284

Note 19. Information Subsequent to Date of Independent Registered Public Accounting Firm Report

On April 2, 2012, we announced that we had entered into an agreement to sell certain assets for $306 million in the Barnett Shale located in north central Texas, as well as our interests in the Arkoma Basin in southeastern Oklahoma. These assets include interests in undeveloped acreage, producing wells, and pipelines. The properties represent less than five percent of our year-end 2011 proved domestic reserves and approximately five percent of total production. The transaction is subject to certain closing adjustments that will impact the total proceeds to be received.

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Notes to Consolidated Financial Statements (continued)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(Millions, except per-share amounts)		
2011				
Revenues	$ 984	$ 990	$ 1,022	$ 992
Operating costs and expenses	862	841	928	859
Income (loss) from continuing operations	7	28	19	(326)
Net income (loss)	(1)	28	16	(335)
Amounts attributable to WPX Energy:				
Net income (loss)	(3)	25	14	(338)
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	0.02	0.13	0.09	(1.67)
2010				
Revenues	$ 1,164	$ 904	$ 1,006	$ 960
Operating costs and expenses	960	775	882	839
Income (loss) from continuing operations	83	32	(1,410)	20
Net income (loss)	83	31	(1,411)	14
Amounts attributable to WPX Energy:				
Net income (loss)	81	29	(1,413)	12
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	0.41	0.15	(7.17)	0.09

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to rounding.

Net loss for fourth-quarter 2011 includes the following pre-tax items:

$547 million of impairments of producing properties and costs of acquired unproved reserves (see Note 7) and $13 million of impairments related to the Arkoma discontinued operations (see Note 3).

Net income for third-quarter 2011 includes the following pre-tax items:

$50 million write-off of leasehold costs associated with approximately 65 percent of our Columbia County, Pennsylvania acreage;

$11 million of dry hole costs associated with an exploratory Marcellus Shale well in Columbia County;

Net loss for third-quarter 2010 includes the following pre-tax items:

$1,003 million impairment of goodwill (see Note 7);

$678 million of impairments of certain producing properties and acquired unproved reserves (see Note 7);

$15 million of exploratory dry hole costs.

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WPX Energy, Inc.

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. The following information excludes our gas management activities.

With the exception of Capitalized Costs in 2011 and the Results of Operations for all years presented, the following information includes our Arkoma Basin operations which have been reported as discontinued operations in our consolidated financial statements. These operations represent less than one percent of our total domestic and international proved reserves for all periods presented.

Capitalized Costs

	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

	As of December 31, 2011			
	Domestic	International	Consolidated Total	Entity s share of international equity method investee
Proved Properties	$ 10,116	$ 259	$ 10,375	$ 254
Unproved properties	1,686	3	1,689	
	11,802	262	12,064	254
Accumulated depreciation, depletion and amortization and valuation provisions	(3,696)	(133)	(3,829)	(154)
Net capitalized costs	$ 8,106	$ 129	$ 8,235	$ 100

Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $349 million and $312 million, net, for 2011 and 2010, 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, Inc.

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, 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
For the Year Ended December 31, 2011			
Acquisition	$ 45	$	$
Exploration	31	20	8
Development	1,461	24	26
	$ 1,537	$ 44	$ 34

Costs incurred include capitalized and expensed items.

Acquisition costs are as follows: The 2011 costs are primarily for additional leasehold in the Appalachian basin. The 2010 costs are primarily for additional leasehold in the Williston and Appalachian 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.

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. While the immediate offsets are frequently in the dewatering stage, the development classification better reflects the low risk profile of the costs incurred.

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

Results of Operations

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2009			
Revenues:			
Natural gas sales	$ 1,916	$ 13	$ 1,929
Natural gas liquid sales	136	3	139
Oil and condensate sales	38	59	97
Other revenues	39	3	42
Total revenues	2,129	78	2,207
Costs:			
Lease and facility operating	247	16	263
Gathering, processing and transportation, including expenses with Williams	273		273
Taxes other than income	80	13	93
Exploration	53	1	54
Depreciation, depletion and amortization	869	17	886
Impairment of costs of acquired unproved reserves	15		15
General and administrative	221	9	230
Other (income) expense	33	1	34
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

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2010			
Revenues:			
Natural gas sales	$ 1,797	$ 15	$ 1,812
Natural gas liquid sales	282	3	285
Oil and condensate sales	57	71	128
Other revenues	40		40
Total revenues	2,176	89	2,265
Costs:			
Lease and facility operating	267	19	286
Gathering, processing and transportation, including expenses with Williams	326		326

Taxes other than income	109	16	125
Exploration	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)

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

	Domestic	International (Millions)	Total
For the Year Ended December 31, 2011			
Revenues:			
Natural gas sales	$ 1,779	$ 16	$ 1,795
Natural gas liquid sales	404	4	408
Oil and condensate sales	229	86	315
Other revenues	9	4	13
Total revenues	2,421	110	2,531
Costs:			
Lease and facility operating	268	27	295
Gathering, processing and transportation, including expenses with Williams	499		499
Taxes other than income	119	21	140
Exploration	131	3	134
Depreciation, depletion and amortization	927	22	949
Impairment of certain natural gas properties in the Ft. Worth Basin	180		180
Impairment of certain natural gas properties in the Powder River Basin	276		276
Impairment of costs of acquired unproved reserves	91		91
General and administrative	256	12	268
Other (income) expense	(2)	3	1
Total costs	2,745	88	2,833
Results of operations	(324)	22	(302)
(Provision) benefit for income taxes	119	(8)	111
Exploration and production net income (loss)	$ (205)	$ 14	$ (191)

Amount for all years exclude the equity earnings from the international equity method investee. Equity earnings from this investee were $24 million, $16 million and $14 million in 2011, 2010 and 2009, respectively.

Natural gas revenues consist 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. The lower reserves in fourth quarter 2009 were primarily a result of the application of new rules issued by the SEC.

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

Proved Reserves

Our proved reserves were previously reported on a combined products basis, however, with the increase in the significance of our oil and natural gas liquids reserves estimates we have separated our disclosure into natural gas, oil and natural gas liquids. As a result, previously reported periods have been recast to reflect the current presentation. The International reserves are primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest. The Entity s share of international equity method investee represents Apco s 40.8% interest in reserves of Petrolera Entre Lomas S.A.

	Natural Gas (Bcf)			
	Domestic	International	Entity s share of international equity method investee	Combined
Proved reserves at December 31, 2008	**4,321.3**	**74.4**	**23.9**	**4,419.6**
Revisions	(984.5)	7.3	0.7	(976.5)
Purchases	156.4			156.4
Extensions and discoveries	998.4	11.8	15.3	1,025.5
Production	(421.9)	(9.0)	(3.8)	(434.7)
Proved reserves at December 31, 2009	**4,069.7**	**84.5**	**36.1**	**4,190.3**
Revisions	(274.7)	(13.1)	2.2	(285.6)
Purchases	37.3			37.3
Extensions and discoveries	478.7	11.9	13.7	504.3
Production	(396.8)	(9.0)	(3.8)	(409.6)
Proved reserves at December 31, 2010	**3,914.2**	**74.3**	**48.2**	**4,036.7**
Revisions	(279.4)	0.2	(4.0)	(283.2)
Purchases	8.0			8.0
Divestitures	(12.8)			(12.8)
Extensions and discoveries	769.7	9.6	11.5	790.8
Production	(416.8)	(9.1)	(4.7)	(430.6)
Proved reserves at December 31, 2011	**3,982.9**	**75.0**	**51.0**	**4,108.9**
Proved developed reserves at December 31, 2009	2,298.4	55.0	23.0	2,376.4
Proved developed reserves at December 31, 2010	2,368.5	43.4	27.9	2,439.8
Proved developed reserves at December 31, 2011	2,497.3	48.4	28.5	2,574.2

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

	NGLs (MMBbls)			
	Domestic	International	Entity s share of international equity method investee	Combined
Proved reserves at December 31, 2008		**0.7**	**0.8**	**1.5**
Revisions	50.3	0.1		50.4
Purchases	0.1			0.1
Extensions and discoveries	18.4	0.3	0.3	19.0
Production	(4.7)	(0.1)	(0.1)	(4.9)
Proved reserves at December 31, 2009	**64.1**	**1.0**	**1.0**	**66.1**
Revisions	30.7			30.7
Purchases	0.2			0.2
Extensions and discoveries	8.9	0.1	0.2	9.2
Production	(8.1)	(0.1)	(0.1)	(8.3)
Proved reserves at December 31, 2010	**95.8**	**1.0**	**1.1**	**97.9**
Revisions	23.0	(0.1)	(0.1)	22.8
Purchases	0.3			0.3
Extensions and discoveries	25.0			25.0
Production	(10.1)	(0.1)	(0.1)	(10.3)
Proved reserves at December 31, 2011	**134.0**	**0.8**	**0.9**	**135.7**
Proved developed reserves at December 31, 2009	**31.6**	**0.8**	**0.7**	**33.1**
Proved developed reserves at December 31, 2010	**48.7**	**0.7**	**0.7**	**50.1**
Proved developed reserves at December 31, 2011	**72.1**	**0.6**	**0.6**	**73.3**

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

	Oil (MMBbls)			
	Domestic	International	Entity s share of international equity method investee	Combined
Proved reserves at December 31, 2008	**2.9**	**8.9**	**9.9**	**21.7**
Revisions	0.8	0.7	0.8	2.3
Purchases	0.5			0.5
Extensions and discoveries	1.3	2.9	3.9	8.1
Production	(0.8)	(1.4)	(1.6)	(3.8)
Proved reserves at December 31, 2009	**4.7**	**11.1**	**13.0**	**28.8**
Revisions	(0.9)	0.1	0.3	(0.5)
Purchases	20.5			20.5
Extensions and discoveries	0.9	2.0	1.7	4.6
Production	(0.9)	(1.3)	(1.6)	(3.8)
Proved reserves at December 31, 2010	**24.3**	**11.9**	**13.4**	**49.6**
Revisions	1.2	(0.7)	(0.9)	(0.4)
Extensions and discoveries	24.3	1.5	1.3	27.1
Production	(2.7)	(1.4)	(1.6)	(5.7)
Proved reserves at December 31, 2011	**47.1**	**11.3**	**12.2**	**70.6**
Proved developed reserves at December 31, 2009	**1.9**	**7.0**	**7.8**	**16.7**
Proved developed reserves at December 31, 2010	**4.0**	**7.1**	**8.1**	**19.2**
Proved developed reserves at December 31, 2011	**13.6**	**6.8**	**7.6**	**28.0**

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

	All products (Bcfe) (1)			
	Domestic	**International**	**Entity s share of international equity method investee**	**Combined**
Proved reserves at December 31, 2008	**4,338.6**	**132.2**	**88.1**	**4,558.9**
Revisions	(678.2)	11.9	5.5	(660.8)
Purchases	159.8			159.8
Extensions and discoveries	1,116.6	31.0	40.5	1,188.1
Production	(455.0)	(18.2)	(14.0)	(487.2)
Proved reserves at December 31, 2009	**4,481.8**	**156.9**	**120.1**	**4,758.8**
Revisions	(95.8)	(12.5)	4.0	(104.3)
Purchases	161.8			161.8
Extensions and discoveries	537.5	24.5	25.1	587.1
Production	(450.3)	(17.5)	(14.0)	(481.8)
Proved reserves at December 31, 2010	**4,635.0**	**151.4**	**135.2**	**4,921.6**
Revisions	(134.3)	(4.6)	(10.0)	(148.9)
Purchases	9.9			9.9
Divestitures	(12.8)			(12.8)
Extensions and discoveries	1,065.5	18.6	19.3	1,103.4
Production	(493.2)	(18.2)	(14.9)	(526.3)
Proved reserves at December 31, 2011	**5,070.1**	**147.2**	**129.6**	**5,346.9**
Proved developed reserves at December 31, 2009	**2,499.3**	**101.8**	**74.0**	**2,675.1**
Proved developed reserves at December 31, 2010	**2,684.4**	**90.1**	**80.7**	**2,855.2**
Proved developed reserves at December 31, 2011	**3,011.5**	**93.0**	**77.7**	**3,182.2**

(1) Oil and natural gas liquids were converted to Bcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

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 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 2009 and 2010 include proved developed reserves of 24 Bcfe and 42 Bcfe, respectively.

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

Revisions in 2011 and 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.

Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit.

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. Prices are based on 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. For the years ended December 31, 2011 and 2010 and 2009, the average domestic natural gas equivalent price, including deductions for gathering, processing and transportation, used in the estimates was $3.89, $3.48 and $2.62 per Mcfe, respectively. The increase in the equivalent price reflects the impact of oil and NGLs growth in our reserves. Future cash inflows for the years ended December 31, 2010 and 2009 reflect deductions for the estimates for gathering, processing and transportation. For the year ended December 31, 2011, the estimates for gathering, processing and transportation are included in production costs. 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 to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

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WPX Energy, Inc.

Supplemental Oil and Gas Disclosures (continued)

(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows

As of December 31, 2010	Domestic	International(1)	Entity s share of international equity method investee(2)
		(Millions)	
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

As of December 31, 2011	Domestic	International(1)	Entity s share of international equity method investee(2)
Future cash inflows	$ 25,498	$ 897	$ 891
Less:			
Future production costs	11,738	340	336
Future development costs	3,484	126	117
Future income tax provisions	3,196	100	117
Future net cash flows	7,080	331	321
Less 10 percent annual discount for estimated timing of cash flows	(3,489)	(132)	(124)
Standardized measure of discounted future net cash inflows	$ 3,591	$ 199	$ 197

(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.

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WPX Energy, Inc.

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, 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

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