QEP Resources, Inc.

QEP Resources, Inc
1050 17th Street, Suite 500
Denver, Colorado 80265

April 3, 2012

To Our Shareholders:

The Annual Meeting of Shareholders of QEP Resources, Inc. will be held on Wednesday, May 15, 2012, at 8:00 a.m. (Mountain Daylight Time), at the Company's corporate offices at 1050 17th Street, 7th Floor, Denver, Colorado.

The corporate secretary's formal notice of the meeting and the proxy statement appear on the following pages and provide information concerning the matters to be considered at the Annual Meeting. After the formal portion of the Annual Meeting, management will review QEP's operational and financial performance during 2011, and provide an outlook for 2012.

Your vote is important. You may attend and vote at the Annual Meeting. However, we encourage you to vote whether or not you are able to attend the Annual Meeting. You may vote by Internet or by telephone using the instructions in the Notice of Internet Availability of Proxy Materials, or if you received a paper copy of the proxy card, by signing and returning it in the envelope provided.

All of the public documents, including our 2011 Annual Report on Form 10-K, are available in the Investor Relations section of our website located at www.qepres.com. The Annual Report does not form any part of the material for solicitation of proxies. We also encourage you to visit our website during the year for more information about QEP.

We hope you will attend the Annual Meeting. We welcome the opportunity to meet with you and to report on our progress. On behalf of the Board of Directors and management, we would like to express our appreciation for your continued support.

Sincerely,

Keith O. Rattie
Chairman of the Board

Charles B. Stanley
President and Chief Executive Officer

QEP Resources, Inc
1050 17th Street, Suite 500
Denver, Colorado 80265

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS
To Be Held on May 15, 2012

To the Shareholders of
QEP Resources, Inc.:

The Annual Meeting of Shareholders of QEP Resources, Inc., a Delaware corporation (QEP or the Company), will be held on May 15, 2012, at 8:00 a.m. (Mountain Daylight Time), at the Company's corporate offices at 1050 17th Street, 7th Floor, Denver, Colorado. The purpose of the meeting is to:

1. Elect two directors to serve three-year terms until the 2015 annual meeting of shareholders, and until their successors are duly elected and qualified;
2. Approve, by non-binding advisory vote, the compensation of the Company's named executive officers as disclosed in the accompanying proxy statement;
3. Approve the material terms of the QEP Resources, Inc. Cash Incentive Plan;
4. Ratify the appointment of PricewaterhouseCoopers LLP as the Company's independent auditor;
5. If presented, vote on a shareholder proposal regarding board declassification; and
6. Transact such other business as may properly come before the meeting or any adjournment or postponement thereof.

Only holders of common stock at the close of business on March 16, 2012, the record date, may vote at the Annual Meeting or any adjournment or postponement thereof. You may revoke your proxy at any time before it is voted. If you have shares registered in the name of a broker, bank or other nominee and plan to attend the meeting, please obtain a letter, account statement, or other evidence of your beneficial ownership of shares to facilitate your admittance to the meeting, and, if you plan to vote at the meeting, you will need to present a valid proxy from the nominee that holds your shares. This proxy statement is being provided to shareholders on or about April 3, 2012.

Your vote is important. Whether or not you plan to attend the Annual Meeting, please vote as soon as possible. You may vote over the Internet, as well as by telephone or by mailing a proxy card. Voting via the Internet, by phone or by written proxy will ensure your representation at the Annual Meeting if you do not attend in person. Please review the instructions you received regarding each of these voting options. Voting over the Internet or by telephone is fast and convenient, and your vote is immediately tabulated. By using the Internet or telephone, you help reduce the Company's cost of postage and proxy tabulations.

By Order of the
Board of Directors

Abigail L. Jones
Corporate Secretary

Denver, Colorado
April 3, 2012

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Shareholders to be held on May 15, 2012: The proxy statement and annual report are available online at www.qepres.com

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QEP RESOURCES, INC.

PROXY STATEMENT
ANNUAL MEETING OF SHAREHOLDERS
May 15, 2012

GENERAL INFORMATION

The Board of Directors (the Board) of QEP Resources, Inc. (the Company or QEP) is soliciting proxies for use at the Annual Meeting of Shareholders (the Annual Meeting) to be held on May 15, 2012, beginning at 8:00 a.m. (Mountain Daylight Time), at our corporate headquarters located at 1050 Seventeenth Street, 7th Floor, Denver, Colorado 80202, and any postponement or adjournment thereof. This proxy statement and the accompanying Notice of Annual Meeting of Shareholders include information related to the Annual Meeting. Distribution of these proxy solicitation materials is scheduled to begin on or about April 3, 2012. The following information will help you to understand the voting process.

Proxy Materials

In accordance with rules promulgated by the Securities and Exchange Commission (SEC), we may furnish proxy materials, including this proxy statement and our Annual Report to Shareholders, by providing access to these documents on the Internet instead of mailing a printed copy of those materials to shareholders. Most shareholders have received a Notice of Internet Availability of Proxy Materials (the Notice), which provides instructions for accessing our proxy materials on a website or for requesting copies of the proxy materials by mail or e-mail.

If you would like to receive an e-mail or paper copy of the proxy materials for the Annual Meeting and for all future meetings, you should follow the instructions for requesting such materials included in the Notice. Choosing to receive future notices by email will lower the Company's cost of delivery and reduce the environmental impact of printing and distributing the materials.

Entitlement to Vote

Shareholders who owned shares as of the close of business on March 16, 2012, may vote at the Annual Meeting. Each shareholder is entitled to one vote for each share of QEP common stock held on that date.

Voting Items

In accordance with our Bylaws, the Board has determined that the board of directors should consist of seven (7) members, each to serve a three-year term. This year, Phillips S. Baker, Jr. and Charles B. Stanley will run for three-year terms. You will also vote on the compensation of the Company's named executive officers (on an advisory basis), the material terms of the QEP Resources, Inc. Cash Incentive Plan (the Cash Incentive Plan), the ratification of the appointment of PricewaterhouseCoopers LLP (PwC) as the Company's independent registered public accounting firm, and a shareholder proposal regarding declassification of the board of directors (on an advisory basis).

Board Voting Recommendations

The Board makes the following recommendations regarding the proposals:

1. **FOR** the approval of the nominees for director named in this proxy statement;

2. **FOR** the approval, by non-binding advisory vote, of the compensation of the Company's named executive officers;

3. **FOR** the approval of the material terms of the Cash Incentive Plan;

4. **FOR** the ratification of PricewaterhouseCoopers LLP as the Company's independent registered public accounting firm; and

5. **NO RECOMMENDATION** regarding the advisory shareholder proposal on Board declassification.

Voting Instructions

You may vote via the Internet. You may vote by proxy over the Internet by following the instructions provided in the Notice or on the proxy card.

You may vote via the telephone. You may submit your vote by proxy over the telephone by following the instructions provided in the Notice or on the proxy card.

You may vote by mail. If you received a printed set of the proxy materials, you may submit your vote by completing and returning the separate proxy card in the prepaid, addressed envelope.

You may vote in person at the meeting. All shareholders of record may vote in person by ballot at the Annual Meeting. Written ballots will be passed out to anyone who wants to vote at the meeting.

Shares Held by a Bank, Broker or Other Nominee

If your shares are held by a broker, bank or other nominee (*i.e.* in "street name"), please refer to the instructions provided by that broker, bank or nominee regarding how to vote your shares. If you wish to vote in person at the Annual Meeting, you must obtain a valid proxy from the nominee that holds your shares.

New York Stock Exchange (NYSE) rules determine whether proposals presented at shareholder meetings are routine or not. If a proposal is routine, a broker or other entity holding shares for an owner in street name may vote on the proposal without receiving voting instructions from the owner. If a proposal is not routine, the broker or other entity may vote on the proposal only if the owner has provided voting instructions. A broker non-vote occurs when the broker or other entity is unable to vote because the proposal is not routine and the owner does not provide instructions.

Pursuant to NYSE rules, if you are the "street name" holder and you do not provide instructions to your broker on Item No. 4 below, your broker may vote your shares at its discretion on this matter. If you are a "street-name" holder and do not provide instructions to your broker on Item Nos. 1, 2, 3, and 5, your broker may not vote your shares on these matters.

Proxy Solicitation

The Company is soliciting your proxy and paying for the solicitation of proxies and will reimburse banks, brokers, and other nominees for reasonable charges to forward materials to beneficial holders. The Company has hired Georgeson Inc. (Georgeson) to assist it in the distribution of proxy materials and the solicitation of votes. The Company will pay Georgeson a base fee of $15,000 plus customary costs and expenses for these services and has agreed to indemnify Georgeson against certain liabilities in connection with its engagement.

Quorum Requirements

On March 16, 2012, the record date, the Company had 177,714,028 shares of common stock issued and outstanding. A majority of the shares, or 88,857,015 shares, constitutes a quorum. Abstentions, withheld votes and broker non-votes are counted for determining whether a quorum is present.

Voting Standards

Election of Directors: Election of the director nominees named in Proposal No. 1 requires the affirmative vote of a plurality of the shares of our common stock present in person or represented by proxy at the Annual Meeting and entitled to vote. Shares represented by executed proxies will be voted, if authority to do so is not withheld, for the election of the nominees named in Proposal No. 1. Votes may be cast in favor of or withheld with respect to both of the director nominees, or either of them. Broker non-votes, if any, will not be counted as having been voted and will have no effect on the outcome of the vote on the election of directors. Shareholders may not cumulate votes in the election of directors.

Approval, by Non-Binding Advisory Vote, of the Compensation of the Company's Named Executive Officers. The vote to approve, on an advisory basis, the Company's executive compensation in Proposal No. 2 requires the affirmative vote of a majority of the shares of our common stock present in person or by proxy at the Annual Meeting and entitled to vote on the matter. Although non-binding, our Board and Compensation Committee will review and consider the voting results when making future decisions regarding our executive compensation program. For purposes of determining whether the proposal has received a majority vote, abstentions will be included in the vote totals, and, therefore, an abstention has the same effect as a negative vote. Broker non-votes will not be included in the vote totals and, therefore, will have no effect on the vote.

Approval of Material Terms of the Cash Incentive Plan: Approval of the material terms of the Cash Incentive Plan under Delaware law requires the affirmative vote of a majority of the shares of our common stock present in person or by proxy at the Annual Meeting and entitled to vote on the proposal. For purposes of satisfying the shareholder approval requirement under Section 162(m) of the Internal Revenue Code of 1986, as amended (the Code), only, the proposal is approved if a majority of the votes cast on the issue are cast in favor of approval. For purposes of determining whether the proposal has received a majority vote under Delaware law and under Section 162(m) of the Code, abstentions will be included in the vote totals, therefore, an abstention has the same effect as a negative vote. Broker non-votes will not be included in the vote totals, and, therefore, will have no effect on the vote.

Ratification of the Company's Independent Auditor: Ratification of the selection of PwC as the Company's independent auditor for fiscal year 2012, requires the affirmative vote of a majority of the shares of our common stock present in person or by proxy at the Annual Meeting and entitled to vote on the matter. If this selection is not ratified by shareholders, the Audit Committee may reconsider its decision. For purposes of determining whether this proposal has received a majority vote, abstentions will be included in the vote totals; therefore, an abstention has the same effect as a negative vote. Broker non-votes will not be included in the vote totals and, therefore, will have no effect on the vote.

Shareholder Proposal: Approval of the advisory shareholder proposal requires the affirmative vote of a majority of the shares of our common stock present in person or by proxy at the Annual Meeting and entitled to vote on the matter. For purposes of determining whether the proposal has received a majority vote, abstentions will be included in the vote totals, therefore, an abstention has the same effect as a negative vote. Broker non-votes will not be included in the vote totals and, therefore, will have no effect on the vote.

Other than the items of business described in this proxy statement, we do not expect any other matter to come before the Annual Meeting. If any other matter is presented at the Annual Meeting, your signed proxy gives the named proxies authority to vote your shares at their discretion.

The Annual Meeting

Any shareholder of record as of March 16, 2012, may attend the Annual Meeting. If you own shares through a bank, broker or other nominee and you wish to attend the meeting, please obtain a letter, account statement, or other evidence of your ownership of shares as of such date. Directions to the Annual Meeting from the Denver International Airport are as follows: take Pena Boulevard to I-70 West, follow I-70 West and then exit onto I-25 South, exit at 38th Ave./Park Ave., merge onto Park Ave. West which becomes 22nd Street, turn right onto Larimer Street, turn left onto 17th Street, 1050 17th Street is on your right.

Revoking a proxy

You may revoke your proxy by submitting a new proxy with a later date, including a proxy submitted via the Internet or telephone, or by notifying the corporate secretary before the meeting by mail at the address shown on the Notice of Annual Meeting of Shareholders. If you attend the Annual Meeting in person and vote by ballot, any previously submitted proxy will be revoked.

ITEM NO. 1 – ELECTION OF DIRECTORS

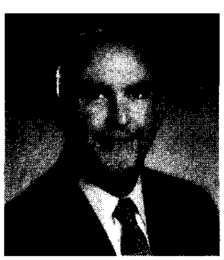
The Company's Bylaws provide for a Board of between seven and eleven directors, with the precise number to be determined by the full Board from time to time. The Board has set the size at seven directors. Our Certificate of Incorporation and Bylaws provide for the Board to be divided into three classes of directors, as nearly equal in number as possible, serving staggered three-year terms. Approximately one-third of the Board will be elected each year.

The terms of two directors, Phillips S. Baker and Charles B. Stanley expire at this Annual Meeting. They have been nominated for election to three-year terms. These individuals have consented to being named in this proxy statement and to serve as directors, if elected. However, in the event that any nominee is unwilling or unable to serve as a director, those named in the proxy may vote, at their discretion, for any other person.

Biographical information concerning the nominees, and the current directors of the Company whose terms will continue after the Annual Meeting, appears below. Unless otherwise indicated, such individuals have been engaged in the same principal occupation for the past five years. Ages are correct as of the date of the proxy statement.

Nominees (Terms Expiring in 2012)

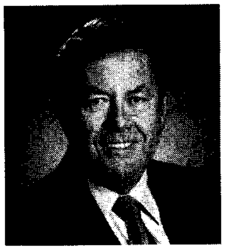
Mr. Phillips S. Baker, Jr., age 52, has served as a Director of QEP since the spin-off from Questar Corporation (Questar) in 2010. He served as a director of Questar from 2004 until the spin-off. Mr. Baker is the President, Chief Executive Officer and a director of Hecla Mining Company, a gold and silver mining company. Mr. Baker served as Chief Financial Officer of Hecla from May 2001 to June 2003, and as Chief Operating Officer of Hecla from November 2001 to May 2003, before being named as Chief Executive Officer in May 2003. Mr. Baker has 27 years of business experience, including 18 years of financial management; seven years as chief executive officer of an NYSE-listed company; and 17 years of directorships of public companies. In concluding that Mr. Baker is qualified to serve as a director, the Board considered, among other things, his financial knowledge and executive management experience and his qualification as an audit committee financial expert.



Mr. Charles B. Stanley, age 53, has served as President, Chief Executive Officer and a director of QEP since June 2010. He served as Executive Vice President and Chief Operating Officer of Questar until the spin-off. Mr. Stanley also served as a director of Questar from 2002 until the spin-off. Prior to joining Questar, he served as President, Chief Executive Officer and a director of El Paso Oil and Gas Canada, an upstream oil and gas company from 2000 to 2002, and as President and Chief Executive Officer of Coastal Gas International Company, a midstream infrastructure development company, from 1995 to 2000. He is a director of Hecla Mining Company and serves on the boards of various natural gas industry trade organizations, including America's Natural Gas Alliance and the American Exploration and Production Council. In concluding that Mr. Stanley is qualified to serve as a director, the Board considered, among other things, his more than 27 years of experience in the international and domestic upstream and midstream oil and gas industry.

The Board recommends that you vote FOR each of the nominees listed above.

Continuing Directors (Terms Expiring in 2013)

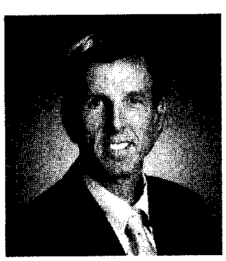


Mr. L. Richard Flury, age 64, has been a director of the Company since June 2010. He served on the Questar Board from 2002 until the spin-off. He served as Chief Executive, Gas and Power, for BP plc from January 1999 to December 2001. Prior to working for BP plc and BP Amoco plc, Mr. Flury held a number of key management positions with Amoco Corp., including Chief Executive for Worldwide Exploration and Production. He serves as a director and non-executive chairman of Chicago Bridge and Iron Company N.V., and as a director of Callon Petroleum Company. In determining Mr. Flury's qualification to serve as a director, the Board considered, among other things, his considerable industry experience in all aspects of the natural gas value chain gained during his long career in the oil and gas industry.

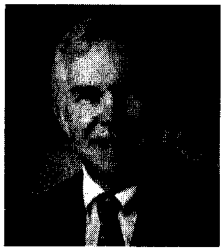
Mr. Robert E. McKee, III, age 65, has been a director of QEP since June 2010. He served as a director of Questar from 2003 until the spin-off. Mr. McKee retired on March 31, 2003, after 37 years with ConocoPhillips and Conoco, Inc., including 10 years as Executive Vice President, Exploration and Production (1992-2002). Mr. McKee was a senior oil advisor to the Coalition Provisional Authority and the Iraqi Oil Ministry in Iraq to assist with the rebuilding of its oil industry from September 2003 to March 2004. He is a director of Parker Drilling Company and Post Oak Bank and a board member of the Colorado School of Mines Foundation. In concluding that Mr. McKee is qualified to serve as a director, the Board considered, among other things, his extensive operational background and executive experience in the oil and gas industry.

Dr. M. W. Scoggins, age 64, has been a director of QEP since 2010. He served as a director of Questar from 2005 until the spin-off. In June 2006, he was appointed President of Colorado School of Mines, an engineering and applied science research university. Dr. Scoggins retired in 2004 after a 34-year career with Mobil Corp. and Exxon Mobil Corp. From 1999 to 2004, he served as Executive Vice President of Exxon Mobil Production Co. Prior to the merger of Mobil and Exxon in late 1999, Dr. Scoggins was President, International Exploration & Production and Global Exploration, and an officer and member of the executive committee of Mobil Corp. Dr. Scoggins currently serves as a director of Venoco, Inc. and Cobalt International Energy. He served on the Board of Trico Marine Services from 2005 until 2011. In addition, he is a member of the National Advisory Council of the United States Department of Energy's National Renewable Energy Laboratory. In concluding that Dr. Scoggins is qualified to serve as a director, the Board considered, among other things, his extensive industry experience and his experience serving in senior executive positions in the upstream oil and gas business.

Continuing Directors (Terms Expiring in 2014)



Mr. Keith O. Rattie, age 58, has served as non-executive chairman of QEP since June 2010. He resigned from his role as President and Chief Executive Officer of Questar upon the spin-off. Mr. Rattie continues to serve as a director and non-executive Chairman of Questar. He was named president of Questar effective February 2001, chief executive officer in May 2002, and chairman in May 2003. Mr. Rattie also serves as a director of ENSCO International, Rockwater Energy Solutions, Inc. and Zions First National Bank. He is the past chairman of the Interstate Natural Gas Association of America. In concluding that Mr. Rattie is qualified to serve as a director, the Board considered, among other things, his 35 years of experience in the natural gas and oil industry and his long history with QEP's businesses as the former chief executive officer of Questar.



Mr. David A. Trice, age 63, has been a QEP director since 2011. He served from February 2000 until his retirement in May 2009, as Chief Executive Officer of Newfield Exploration Company (Newfield), an oil and natural gas exploration and production company. He also served as Chairman of the Board of Newfield from 2004 until 2010. Mr. Trice has served as a director of New Jersey Resources Corporation since 2004 and McDermott International, Inc. since 2009. Mr. Trice previously served as a director of Grant Prideco, Inc. from 2003 to 2008 and as a director of Hornbeck Offshore Services, Inc. from 2002 until February 2011. He is also a director of Crazy Mountain Brewery, LLC, a privately-held company. He served as the Chairman of the American Exploration and Production Council from 2008 to 2009, and as Chairman of America's Natural Gas Alliance from 2009 to 2010. In concluding that Mr. Trice is qualified to serve as a director, the Board considered, among other things, his experience as the chief executive officer of a publicly traded independent exploration and production company and his financial expertise

GOVERNANCE INFORMATION

Recent Corporate Governance Initiatives

Since the 2011 Annual Meeting, we have modified the Company's corporate governance practices. The following list sets forth the new practices:

- In response to shareholder concerns, the Board's review of current trends, and the impact on the Company, the Board voted to accelerate the expiration of the shareholder rights plan so that it expired on April 1, 2012.

- Our Board increased the stock ownership requirement for non-employee directors from two-times to five-times annual cash compensation.

- The Board clarified the oversight of executive sessions. At each regular meeting of the Board, there are sessions involving directors and management, directors only, and independent directors only. During meetings of the independent directors, if the chairman is not an independent director, the presiding director, currently the Governance Committee chair, will preside over the meeting. Although this practice had been in place since the time of the spin-off in 2010, our Corporate Governance Guidelines now clearly set forth the process.

General Governance Information

Excellence in corporate governance is essential in fulfilling our responsibilities to shareholders. The Code of Conduct, Corporate Governance Guidelines, and written charters for our Audit Committee, Governance Committee, and Compensation Committee, all as amended from time to time, are available on the Company's website at www.qepres.com. These documents provide the framework for our corporate governance. Any of these documents will be furnished in print free of charge to any shareholder or other interested party who requests them.

Director Independence

During 2011 and the first three months of 2012, the Board evaluated all business, family and charitable relationships between the Company and the non-employee directors. Our Board has affirmatively determined that, with the exception of Messrs. Rattie and Stanley, all of the Company's directors are independent under all applicable rules and regulations, including listing requirements of the NYSE and the Company's Corporate Governance Guidelines, and no director has a material relationship with the Company that could impair the director's independence. The criteria applied by our Board in determining independence are available on the Company's website at www.qepres.com. The Board will evaluate independence on an ongoing basis.

Board Leadership Structure

Our Board believes that shareholders' interests are best served by providing the Board with flexibility to determine an optimal organizational structure, including whether the chairman role should be held by a non-management director or by the chief executive officer. The members of our Board possess considerable experience and unique knowledge of our Company's challenges and opportunities and consequently are in the best position to evaluate our needs and how best to organize the capabilities of our directors and management to meet those needs. Currently, our Board believes that the appropriate leadership structure is a separate chairman and chief executive officer. The Board may modify this arrangement in the future to ensure that the leadership structure for the Company remains effective and advances the best interests of our shareholders.

Because the current chairman of the Board does not satisfy the NYSE definition of independence, the Board utilizes the role of "presiding director" as part of the leadership structure. One of the Company's independent directors (as defined by the rules of the NYSE) presides at all meetings of the Board at which the chairman is not present, including executive sessions of the independent directors; serves as liaison between the chairman and the independent directors; and has the authority to call meetings of the independent directors. As chair of the Governance Committee, Dr. Scoggins serves as the presiding director.

Board Committees

Our Board has an Audit Committee, a Governance Committee, and a Compensation Committee, which are each comprised solely of independent directors. As noted above, each committee has a charter that can be found on the Company's website (www.qepres.com) and will be provided in print without charge at the request of any shareholder or other interested party. The following section contains information about our Board committees. The members of our Board and the Board committees on which they currently serve are identified below.

Director	Audit Committee	Compensation Committee	Governance Committee
Phillips S. Baker, Jr.	X		X
L. Richard Flury		Chair	X
Robert E. McKee, III	Chair	X	
Keith O. Rattie			
M.W. Scoggins		X	Chair
Charles B. Stanley			
David A. Trice	X	X	

Audit Committee

The Audit Committee reviews auditing, accounting, financial reporting, and internal control functions; and oversees risk assessment and compliance activities. The Audit Committee has the sole authority to hire, compensate, retain, oversee and terminate the Company's independent auditor. The Audit Committee also has sole authority to pre-approve all terms and fees for audit services, audit-related services and other services to be performed by the Company's independent auditor.

The Board has determined that all members of the Audit Committee meet the independence requirements of the NYSE and SEC rules and meet the financial literacy requirements of the NYSE. The Board determined that

Messrs. Baker and Trice are audit committee financial experts as defined by SEC rules. The Audit Committee frequently meets in executive sessions, and meets with the internal auditors and independent auditors outside the presence of management.

Compensation Committee

The Compensation Committee oversees our executive compensation program, benefit plans and policies; administers our short and long-term incentive plans, including equity-based programs; oversees short and long-term, as well as emergency succession planning; approves compensation decisions for officers; recommends chief executive officer total compensation to the full Board; and annually reviews the performance of the chief executive officer. Our Compensation Committee oversees the risk assessment of our executive and nonexecutive compensation programs. The Compensation Committee also oversees compensation decisions regarding our non-employee directors. The Compensation Committee frequently meets in executive sessions to discuss and approve compensation for officers. The Board has determined that each member of the Compensation Committee is independent and that each qualifies as a non-employee director under Rule 16b-3 of the Securities Exchange Act of 1934, as amended (the Exchange Act), and as an outside director under Section 162(m) of the Internal Revenue Code (the Code).

The Compensation Committee has sole authority to retain and dismiss compensation consultants and other advisors that provide objective advice, information, and analysis regarding executive and director compensation. These consultants report directly to and may meet separately with the Compensation Committee, and may consult with the Compensation Committee Chairman between meetings. The Compensation Committee has retained Meridian Compensation Partners, LLC (the Consultant). The Compensation Committee determined that the Consultant is independent from our Company.

The Compensation Committee has authorized Mr. Stanley, our Chief Executive Officer, to grant restricted stock to newly hired employees and for employee retention up to a limit of $175,000 per grant. Mr. Stanley's authority is subject to certain limitations and does not extend to grants to officers or directors. The full Compensation Committee reviews grants made by Mr. Stanley at its next meeting.

Governance Committee

The Governance Committee, which also functions as the Company's nominating committee, is responsible for committee assignments, new director searches, drafting and revising the Corporate Governance Guidelines, reviewing the Code of Conduct, conducting evaluations for the Board and its committees, and making recommendations to the full Board on various governance issues. The Board has determined that all members of the Governance Committee are independent.

The Governance Committee's Charter defines the criteria for director nominees, including nominees recommended by shareholders and self-nominees. These criteria provide a framework for evaluating all nominees as well as incumbent directors. The key criteria are: personal and professional integrity and ethics; experience in the Company's lines of business; experience as a chief executive officer, president, chief financial officer, or senior officer of a public company or extensive experience in finance or accounting; currently active in business at least part-time or recently retired, with skills and experience needed to serve as a member of the Board; experience as a board member of another publicly-held company; willingness to commit time and resources to serve as a director; and good business judgment, including the ability to make independent analytical inquiries. The Board of Directors does not have a formal diversity policy, but considers candidates who will contribute a broad range of talents, skills, diversity and expertise, particularly in the areas of (i) management, (ii) strategic planning, (iii) accounting and finance, (iv) corporate governance, and (v) the oil and natural gas industry, sufficient to provide sound and prudent guidance about the Company's operations and interests. Nominees must be less than 72 years of age.

The Governance Committee will consider director nominations made by shareholders of record entitled to vote. In order to make a nomination for election at the 2013 Annual Meeting of Shareholders, a shareholder must provide written notice, along with supporting information (as described below) regarding such nominee, to our corporate secretary by February 14, 2013. The Governance Committee evaluates nominees recommended by the shareholders utilizing the same criteria it uses for other nominees. The notice to our corporate secretary must be accompanied by the following information: the name, address, and stock ownership of the person making the nominations; the name, age, business address, residential address, and principal occupation or employment of each nominee; the number of shares of our common stock owned by each nominee; a description of all arrangements and understandings between the shareholder and nominee pursuant to which the nomination is made; a questionnaire (provided by the our corporate secretary upon request) completed by the nominee regarding the background and qualifications of the nominee and any person on whose behalf the nomination is being made; a written representation and agreement (in the form provided by our corporate secretary upon request) that the nominee (i) is not and will not be a party to any voting commitment that has not been disclosed to the Company or that would interfere with the person's fiduciary duties under applicable law if elected; (ii) is not and will not be a party to any compensation, reimbursement, or indemnification agreement in connection with services as a director that has not been disclosed to the Company; and (iii) agrees to comply with all applicable publicly disclosed corporate governance, conflict of interest, confidentiality and stock ownership and trading policies and guidelines of the Company; a signed consent of the nominee to serve as a director if elected; and such other information concerning the nominee as would be required, under SEC rules, in a proxy statement soliciting proxies for the election of the nominee.

Board Risk Oversight

Our Board, as a whole and through its committees, is responsible for overseeing risk management. The Company's executive officers are responsible for day-to-day management of the material risks the Company faces. In its oversight role, our Board has the responsibility to satisfy itself that the risk management processes designed by management are adequate and functioning as designed. Our Board and its committees regularly discuss material risk exposures, risk disclosure, their potential impact on the Company, and the efforts of management to address the identified risks.

A number of Board processes support our risk management program. The full Board reviews regulatory and environmental risks and discusses the Company's enterprise risk management program regularly. The Board reviews and approves the capital budget and certain capital projects, the hedging policy, significant acquisitions and divestitures, equity and debt offerings, and other significant activities.

The Audit Committee plays an important role in risk management by assisting the Board in fulfilling its responsibility to oversee the integrity of the financial statements and our compliance with legal and regulatory requirements. The Audit Committee retains and interacts regularly with our independent auditors and also meets regularly with our internal auditors. Additionally, the Audit Committee reviews financial and accounting risk exposure; the Company's proved oil and gas reserves estimation reporting process and disclosure; and the Company's internal controls. The Audit Committee also oversees ethics and compliance procedures and reporting.

The Compensation Committee reviews the compensation program to ensure it is aligned with our compensation objectives and to address any potential risks it may create. The Compensation Committee has designed our short- and long-term compensation plans with features that reduce the likelihood of excessive risk-taking, including a balanced mix of cash and equity, short- and long-term incentives, an appropriate balance of operating and financial performance measures, a proper balance of fixed and at-risk compensation components, significant stock ownership requirements for executives, extended vesting schedules on equity grants, and caps on incentive awards.

Our Governance Committee's role in risk management includes regularly reviewing developments in corporate governance, and reviewing our Code of Conduct and Corporate Governance Guidelines in order to recommend appropriate action to the full Board. The Governance Committee also establishes criteria for and determines director independence, provides input for Board membership and committee assignments, and makes adjustments to ensure that we have appropriate director expertise to oversee the Company's evolving business operations.

Stock Ownership Guidelines for Non-Employee Directors

Our Board has adopted stock ownership guidelines for non-employee directors to align the interests of our directors with the interests of our shareholders and to promote our commitment to best practices in corporate governance. Non-employee directors are required to hold shares of our common stock with a value equal to five-times the amount of the annual cash compensation paid to such director for service on our Board. Non-employee directors are required to achieve the applicable level of ownership within five years of the date the director first became a non-employee member of the Board. Shares that count towards satisfaction of the guidelines include shares owned by the director and phantom stock units attributable to deferred compensation. All of our non-employee directors, regardless of their term of service, currently hold a sufficient number of shares of our common stock to satisfy these guidelines.

Compensation Committee Interlocks and Insider Participation

The members of our 2011 Compensation Committee were Messrs. Flury, McKee, Scoggins and Trice (with Mr. Trice joining the committee in May 2011). No member of our Compensation Committee was at any time during 2011 an officer or employee of the Company. Additionally, no member of the Compensation Committee had any relationship with our Company requiring disclosure as a related-party transaction. During the 2011 fiscal year, no executive officer of our Company served on the compensation committee of any other entity that had one or more of its executive officers serving as a member of our Compensation Committee.

Communications with Directors

Shareholders may communicate with the full Board, non-management directors as a group, or individual directors, by sending a letter in care of Corporate Secretary at QEP Resources, Inc., 1050 17th Street, Suite 500, Denver, Colorado 80265. Our corporate secretary has the authority to discard any solicitations, advertisements, or other inappropriate communications, but will forward any other mail to the named director or group of directors. Any mail that is directed to the full Board will be directed to Mr. Rattie as Chairman of the Board and forwarded to the full Board, if appropriate.

Attendance at Meetings

The QEP Board and Board committees held the following number of meetings in 2011:

	Board	Audit Committee	Compensation Committee	Governance Committee
Number of 2011 Meetings	4	7	5	3

All directors attended at least 75% of the meetings. Our directors are expected to attend the Company's annual meetings of shareholders. The directors' overall meeting attendance percentage was 99%. All of the directors attended the 2011 Annual Meeting.

Family Relationships

None of the current directors or executive officers is related to any other director or executive officer.

Director Retirement Policy

Our Board has adopted a retirement policy that permits a non-employee director to continue serving until the annual meeting of shareholders following his or her 72nd birthday, provided that the director remains actively engaged in business, financial, and community affairs.

CERTAIN RELATIONSHIPS AND TRANSACTIONS WITH RELATED PERSONS

Transactions with related persons are those that involve our directors, executive officers, director nominees, greater than 5% shareholders, immediate family members of these persons, or entities in which one of these persons has a direct or indirect material interest. We review all transactions that would involve amounts exceeding $120,000 (the current threshold required to be disclosed in the Proxy Statement under SEC regulations) and certain other similar transactions.

Review and Approval of Transactions with Related Persons

We require that all executive officers and directors report to our vice president, compliance, any event or anticipated event that might qualify as a related-person transaction. The vice president, compliance would then report those transactions to the Audit Committee. We also collect information from questionnaires sent to officers and directors early each year that are designed to reveal related-person transactions. If a report or questionnaire shows a potential related-person transaction, our Audit Committee will review the transaction in accordance with our Code of Conduct. Our Audit Committee will review pending and ongoing transactions to determine whether they conflict with the best interests of the Company, impact a director's independence or conflict with our Code of Conduct. If a related-person transaction is completed, the Audit Committee will determine whether rescission of the transaction, disciplinary action or reevaluation of a director's independence is required. If a waiver to the Code of Conduct is granted to an executive officer or director, the nature of the waiver will be disclosed on our website (www.qepres.com), in a press release, or on a current report on Form 8-K.

Related-Party Transactions during Fiscal 2011

During 2011, we contributed $250,000 in cash to the QEP Resources Education Foundation, a nonprofit corporation that funds student scholarships and other activities at colleges and universities focused on educating and training students in disciplines that prepare students for employment by our Company, such as geology, engineering, and finance. The trustees of the foundation, Mr. Stanley, Mr. Doleshek, Mr. Neese, and Ms. Jones, are all executive officers of the Company.

SECURITY OWNERSHIP

The information provided below summarizes the beneficial ownership of our common stock by our named executive officers, each of our directors, all of our executive officers and directors as a group, and persons owning more than five percent of our common stock. "Beneficial ownership" generally includes those shares of common stock held by someone who has investment and/or voting authority of such shares or has the right to acquire such common stock within 60 days. The ownership includes common stock that is held directly and also stock held indirectly through a relationship, a position as a trustee or under a contract or understanding.

Directors and Executive Officers

The following table lists the shares of our common stock beneficially owned by each director and named executive officer, and all directors and executive officers as a group as of March 16, 2012. Except as noted, each person has sole voting and investment power over the shares shown in the table. On March 16, 2012, there were 177,714,028 shares of common stock outstanding. Shares not outstanding but deemed beneficially owned by virtue of the right of a person to acquire shares within 60 days of March 16, 2012, are included as outstanding and beneficially owned for that person, but are not treated as outstanding for the purpose of computing the percentage ownership of any other person.

	Amount and Nature of Beneficial Ownership			
Name	Common Stock Beneficially Owned(#)(1)(2)	Common Stock Acquirable within 60 Days(#)(3)	Total Beneficially Owned(#)(2)	Percent of Class(%)
Charles B. Stanley	405,435(4)	580,530	985,965(3)	*
Richard J. Doleshek	152,674(5)	130,320	282,994(4)	*
Jay B. Neese	157,399(6)	127,114	284,513(5)	*
Perry H. Richards	41,255(7)	41,124	82,379(6)	*
Eric L. Dady	59,921(8)	12,511	72,432(7)	*
Phillips S. Baker, Jr.	14,897	0	14,897	*
L. Richard Flury	13,788	14,000	27,788	*
Robert E. McKee, III	9,155(9)	14,000	23,155(8)	*
Keith O. Rattie	405,257(10)	882,174	1,287,431(9)	*
M. W. Scoggins	7,700	0	7,700	*
David A. Trice	7,500	0	7,500	*
All directors and executive officers (14 individuals including those listed above)	1,375,345	1,852,772	3,228,117	1.8

* The percentage of shares owned is less than 1%. The percentages of beneficial ownership have been calculated in accordance with Rule 13d-3(d)(1) under the Exchange Act.

(1) This total does not include shares of common stock that directors or executive officers have the right to acquire within 60 days of March 1, 2012.

(2) This total does not include phantom stock units in the director or officer's deferred compensation account or officer long-term cash incentive amounts measured in phantom stock. The directors and officers held the following numbers of phantom shares in their deferred compensation accounts as of March 16, 2012:

Name	Phantom Shares on 3/16/12
Charles B. Stanley	52,927
Richard J. Doleshek	7,057
Jay B. Neese	20,626
Perry H. Richards	4,583
Eric L. Dady	4,469
Phillips S. Baker, Jr.	10,160
L. Richard Flury	40,322
Robert E. McKee, III	55,199
Keith O. Rattie	5,668
M. W. Scoggins	52,645
David A. Trice	8,474

(3) These amounts include shares subject to stock options that will vest within 60 days.
(4) This number includes 12,032 equivalent shares of stock held for Mr. Stanley's account in the QEP 401(k) Plan, and 146,936 shares of unvested restricted stock, with respect to which he receives dividends and has voting power, but which cannot be disposed of until they vest. Excludes amounts tracked as phantom shares under the Deferred Compensation Wrap Plan and the cash incentive plan, that are payable only in cash. All of the vested shares listed for Mr. Stanley are held in the CJ Trust, of which he and his wife are trustees. Excludes 44,907 shares owned by the QEP Resources Educational Foundation, a nonprofit corporation. As chairman of the Board of Trustees of the foundation, Mr. Stanley has voting power for such shares. Mr. Stanley disclaims any beneficial ownership of these shares.
(5) This total includes 882 equivalent shares of stock held for Mr. Doleshek's account in the QEP 401(k) Plan, and 118,082 shares of unvested restricted stock, with respect to which he receives dividends and has voting power, but which cannot be disposed of until they vest. Excludes amounts tracked as phantom shares under the Deferred Compensation Wrap Plan and the cash incentive plan, that are payable only in cash.
(6) This amount includes 30,591 equivalent shares of stock held for Mr. Neese's account in the QEP 401(k) Plan, and 73,395 shares of unvested restricted stock, with respect to which he receives dividends and has voting power, but which cannot be disposed of until they vest. Excludes amounts tracked as phantom shares under the Deferred Compensation Wrap Plan and the cash incentive plan that are payable only in cash.
(7) This amount includes 5,536 equivalent shares of stock held for Mr. Richards' account in the QEP 401(k) Plan, and 17,276 shares of unvested restricted stock, with respect to which he receives dividends and has voting power, but which cannot be disposed of until they vest. Excludes amounts tracked as phantom shares under the Deferred Compensation Wrap Plan and the cash incentive plan, that are payable only in cash.
(8) This total includes 5,956 equivalent shares of stock held for Mr. Dady's account in the QEP 401(k) Plan, and 17,362 shares of unvested restricted stock, with respect to which he receives dividends and has voting power, but which cannot be disposed of until they vest. Excludes amounts tracked as phantom shares under the Deferred Compensation Wrap Plan and the cash incentive plan, that are payable only in cash.
(9) This amount includes 200 shares of common stock held by The McKee Family Trust.
(10) This total excludes 34,255 restricted stock units issued to Mr. Rattie, with respect to which Mr. Rattie receives dividends but does not have voting power and which cannot be disposed of until they vest.

Certain Beneficial Owners

The following table sets forth information, as of December 31, 2011, with respect to each person known by the Company to beneficially own more than five percent of our common stock.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
BlackRock, Inc. **40 East 52nd Street** **New York, NY 10022**	13,931,375(1)	7.87%
T. Rowe Price Associates, Inc. **P.O. Box 17218** **Baltimore, MD 21297**	12,450,642(2)	7%
The Vanguard Group, Inc. **100 Vanguard Blvd.** **Malvern, PA 19355**	9,746,864(3)	5.5%

(1) Based upon its Schedule 13G filed with the SEC with regard to our common stock held as of December 31, 2011, BlackRock has sole dispositive and voting power over all of the referenced shares.
(2) Based upon its Schedule 13G filed with the SEC with regard to our common stock held as of December 31, 2011, T. Rowe Price has sole dispositive power over all of the referenced shares, and sole voting power with respect to 2,573,687 shares.

(3) Based upon its Schedule 13G filed with the SEC with regard to our common stock held as of December 31, 2011, Vanguard has sole dispositive power over 9,499,634 of the referenced shares, and sole voting power with respect to 247,230 shares.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Pursuant to Section 16(a) of the Exchange Act and regulations promulgated by the SEC, the Company's directors, executive officers, and persons who own more than 10% of the Company's stock are required to file reports of ownership and changes in ownership with the SEC and to furnish the Company with copies of all such reports they file. The Company's corporate secretary prepares reports for directors and executive officers based on information known and otherwise supplied, including information provided in response to director and officer questionnaires. Based upon this information, the Company believes that all filing requirements under Section 16(a) of the Exchange Act were satisfied for 2011.

AUDIT COMMITTEE REPORT

The Audit Committee adopted its Charter in 2010 upon formation of the Company. Audit Committee members are appointed each year by the Board of Directors to review the Company's financial matters. The Board has determined that each member of our Audit Committee meets the independence requirements set by the NYSE and is financially literate. The Board has also determined that Messrs. Baker and Trice are audit committee financial experts as defined by the SEC. No member of the Audit Committee serves as a member of the audit committee of more than three public companies.

We reviewed and discussed with the Company's management the audited financial statements for the year ended December 31, 2011. We discussed with representatives of Ernst & Young, LLP, the Company's former independent auditor, the matters required to be discussed by Statement on Auditing Standards No. 61, as amended (AICPA Professional Standards, Vol. 1, AU§ 380), *Communication with Audit Committees*. We have also received the written disclosures and the letter from Ernst & Young required by applicable requirements of the Public Company Accounting Oversight Board regarding Ernst & Young's communications with the Audit Committee concerning independence, and we have discussed with representatives of Ernst & Young and PwC their independence from the Company. We have also discussed with the Company's officers and Ernst & Young and PwC such other matters and received such assurances from them as we deemed appropriate.

Based on our review and discussions, we have recommended to the Company's Board of Directors the inclusion of the audited financial statements in the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

By the Audit Committee:
Robert E. McKee III, Chair
Phillips S. Baker, Jr.
David A. Trice

This report shall not be deemed to be incorporated by reference by any general statement incorporating by reference this proxy statement into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and shall not otherwise be deemed filed under such acts.

COMPENSATION COMMITTEE REPORT

We have reviewed and discussed the Compensation Discussion and Analysis with management and, based on our review and discussions, have recommended to the Board that the Compensation Discussion and Analysis be included in this proxy statement.

By the Compensation Committee:
L. Richard Flury, Chair
Robert E. McKee III
M. W. Scoggins
David A. Trice

This report shall not be deemed to be incorporated by reference by any general statement incorporating by reference this proxy statement into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and shall not otherwise be deemed filed under such acts.

COMPENSATION DISCUSSION AND ANALYSIS

Executive Summary

Summary of Company Performance and Resulting Compensation Outcomes for 2011

During 2011, our executive leadership team led QEP Resources through its first full year as a stand-alone, publicly traded company and the Company continued to deliver strong financial and operational results driven primarily by:

- the leadership and financial discipline of our management team;
- the quality of our assets;
- our low cash cost of production;
- our complementary midstream business; and
- a commodity price risk management program that uses derivative instruments to protect revenues from a portion of our production against a decline in the prices of natural gas, crude oil, and natural gas liquids (NGL).

During 2011, we continued to lay the foundation for significant future growth while maintaining our strong balance sheet and financial flexibility. With focused leadership on key strategic issues, our management team delivered strong operating and financial results, including the following:

- Achieved Adjusted EBITDA[1] of $1,386 million for 2011, compared with $1,140 million in 2010, a 22% increase;
- Replaced 312% of 2011 production at a proved developed finding and development cost of $2.07/Mcfe;

[1] Adjusted EBITDA is a non-GAAP measure. Management defines adjusted EBITDA as net income before the following items: discontinued operations, unrealized gain and losses on basis-only swaps, gains and losses from assets sales, interest and other income, income taxes, interest expense, separation costs, loss on early extinguishment of debt, depreciation, depletion and amortization, abandonment and impairment, and exploration expense. A reconciliation of adjusted EBITDA to net income can be found on page 39 of our Annual Report on Form 10-K for the year ended December 31, 2011 (2011 Form 10-K). Adjusted EBITDA is used to determine amounts payable under our annual incentive plan.

- Increased natural gas and oil-equivalent production by 20% to 275 Bcfe;

- Achieved 54% growth in crude oil and NGL production and 107% growth in crude oil and NGL reserves over 2010 volumes;

- Completed construction, started up and began operating two major new gas processing facilities in Field Services – the Iron Horse Plant in eastern Utah and the Blacks Fork II plant in western Wyoming;

- Achieved record financial and operating performance in our Field Services segment;

- Completed a successful spin-off from Questar, with uninterrupted strong operational performance, while simultaneously building the organization needed to run a new, fully independent, publicly traded company;

- Significantly enhanced our ability to attract, retain and motivate key talent by retooling our key people programs; and

- Maintained our relative total shareholder return (TSR) position at the median of our peer group with only a slight decline in TSR in 2011.

Our operating and financial performance, along with the achievement of key strategic goals and the individual performance of our executive officers, served as key factors in determining base salaries, annual incentive awards, and long-term incentive awards for 2011. Below is a summary of these compensation decisions:

Base Salary	**Our executive officers received an increase to their base salaries of approximately 4%, consistent with the average increase for non-executive employees, except in the case of the two executive officers who received more significant increases in order to adjust their base salaries to an appropriate level commensurate with their expanded roles as corporate officers of a public company following the spin-off.**
Annual Cash Incentive	Under our annual cash incentive program, our named executive officers received a payout at 145% of target (except for Mr. Richards, who received 174% of target) based on the achievement of performance goals designed to measure annual company performance and drive long-term shareholder value creation. We increased both cash flow as measured by Adjusted EBITDA and production in excess of the target level. We maintained a competitive cost structure but did not achieve targeted proved developed finding and development (F&D) costs, in part because of our focus on increasing the number of oil wells, which typically have higher F&D costs than gas wells. In addition, we achieved a number of key strategic goals that position us well for future success.
Long-Term Incentives	**As no previous performance share unit awards were outstanding (due to conversion to restricted stock units in connection with the spin-off), there were no cash payouts under long-term incentive awards for 2011. In February 2011, the Compensation Committee awarded new restricted stock, stock options and performance share units designed to incentivize performance that drives long-term shareholder value.**

Key Program Changes in 2011

After QEP's spin-off from Questar in 2010, the Compensation Committee, with the assistance of its independent compensation consultant and management, worked to redesign our compensation programs to meet our needs as an independent exploration and production company. The goals of this process were to:

- Strengthen the link between pay and performance;

- Build greater alignment with shareholders through the significant weighting on long-term incentive compensation for officers, as well as stock ownership guidelines for officers;

- Enhance competitive alignment with an appropriate exploration and production peer group; and

- Eliminate or limit the use of executive programs and protections consistent with evolving governance standards.

In 2011 we conducted our first shareholders' advisory vote on executive compensation, or "Say on Pay," which was approved by our shareholders. As a result of the Say on Pay vote, we engaged in discussions with institutional investors and their advisors to gather feedback regarding out executive compensation programs. We received input that the excise tax gross-up in our executive severance plan was no longer consistent with executive compensation best practices but that the remaining structure of our executive compensation program was well positioned for the future. As a result of that feedback and consistent with our goals in redesigning our compensation programs following the spin-off, the Compensation Committee approved the following changes to our executive compensation program:

- Removal of excise tax gross-ups from our severance protections;

- Introduction of a new peer group for benchmarking compensation and performance consisting solely of independent, publicly-traded predominantly domestic exploration and production organizations, as set forth on page 20;

- Revisions to our annual incentive program design which strengthen the link between pay and performance and improve competitiveness, as set forth in more detail on pages 22-24; and

- Improvements to our long-term incentive program to provide that at least one-third of awards under the program are performance-based awards tied to relative shareholder return over a three-year period; another one-third of awards are in the form of stock options that will provide value to the executive only if the Company's stock price increases; and the final one-third is awarded in restricted stock that increases executive share ownership.

Named Executive Officers

The named executive officers who will be discussed throughout this *Compensation Discussion and Analysis* section and the *Compensation Tables* section of the proxy statement are:

Name	Title
Charles B. Stanley	President and Chief Executive Officer
Richard J. Doleshek	Executive Vice President, Chief Financial Officer and Treasurer
Jay B. Neese	Executive Vice President
Perry H. Richards	Senior Vice President – Field Services
Eric L. Dady	Vice President and General Counsel

Compensation Philosophy

Our executive compensation programs are designed to attract, retain and reward effective leaders. The Board believes that industry leadership in oil and gas requires a balanced perspective to effectively manage the inherent investment risks associated with oil and gas exploration and production as well as midstream gas gathering and processing businesses, over both short-term and long-term time horizons.

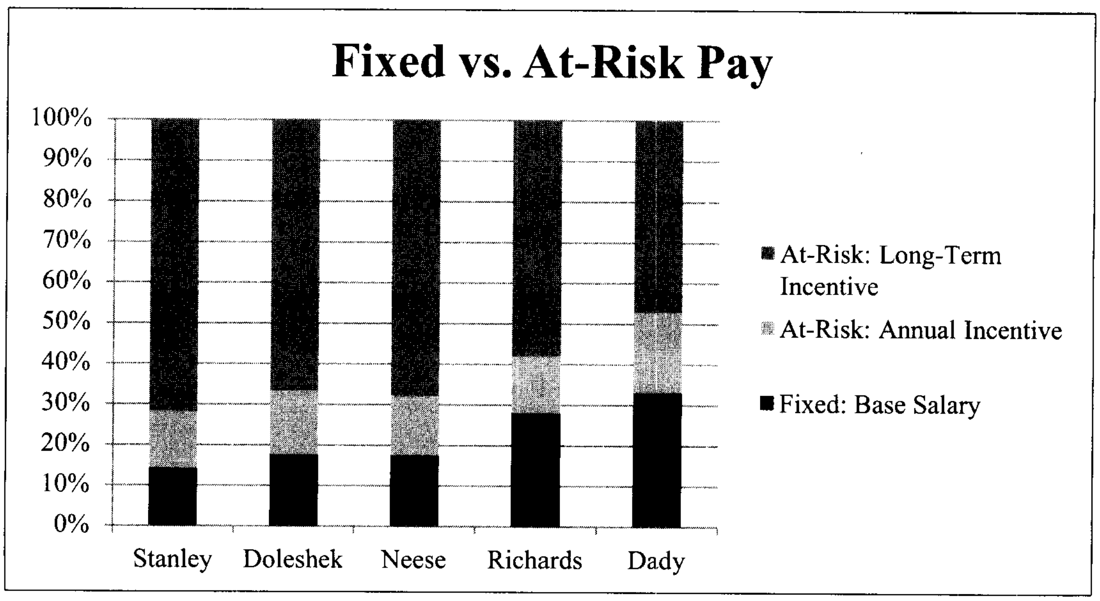
Our compensation programs are designed to support a performance-based culture that is focused on delivering sustainable growth and creating long-term shareholder value. We offer our executives industry-competitive compensation opportunities that directly correlate pay with the performance of the company and the executive team, considering short-term performance against company goals, long-term performance relative to our peers, and total shareholder return. The majority of each executive's compensation is variable and based on these performance parameters.

Our executive compensation program is not targeted to a specific percentile of the peer market data. We evaluate the range of current industry compensation practices to provide external benchmarks that inform our executive compensation structure. Our Compensation Committee determines individual total compensation opportunities within this framework to provide realized compensation relative to peers that correlates with the company's relative performance to peers. This approach provides the flexibility needed to manage our executive compensation programs to meet our current business needs.

Design of the Compensation Program

Our pay-for-performance philosophy is demonstrated in the mix of compensation that we provide for our Named Executive Officers. A significant portion of our officers' compensation is in the form of Annual Cash Incentive and Long-Term Incentive. Each of these incentives plays a different role in aligning pay with QEP's performance and the long-term financial interests of our executives with those of our shareholders. The annual plan aligns executive pay with achievement of annual operational and financial goals designed to enhance QEP's long-term value. Long-term incentives deliver value to the executives to the extent that QEP's stock price performs well, both on an absolute basis and relative to peer companies.

The chart below identifies the mix of fixed pay (salary) versus at-risk pay (incentives) as a percentage of target total compensation, (excluding benefits and termination benefits) for the 2011 compensation period.



Compensation Process

Our Compensation Committee is guided by the compensation philosophy and objectives described above. In addition, our Compensation Committee utilizes the expertise and objectivity of outside independent compensation consultants, as well as competitive benchmarking.

Role of Compensation Consultants

Our Compensation Committee engaged Meridian Compensation Partners (the Consultant) as its compensation consultant to help ensure that our executive compensation programs are competitive and consistent with our compensation philosophy. In making this decision, the Compensation Committee considered the Consultant's performance in supporting the committee with respect to 2010 compensation matters, its extensive experience, its familiarity with our executive compensation program and the compensation programs of our peer companies and sector, the range of compensation services offered by the Consultant, the absence of any business or personal relationship between the Consultant and any member of the Compensation Committee or management, and the Consultant's policies and procedures designed to avoid potential conflicts of interest arising out of the provision of services with respect to the Company. The Consultant attended all Compensation Committee meetings, including executive sessions as needed. Our Compensation Committee hired the Consultant in June 2010 and determined the scope of the engagement, which included:

- Providing benchmarking data on executive and outside director compensation for the Compensation Committee to use in its decision-making process;
- Providing input into plan design discussions and individual compensation actions, as needed;
- Periodic plan design review and recommendations;
- Reviewing and providing feedback on the compensation-related disclosures in our proxy statement; and
- Informing the Compensation Committee about recent trends, best practices and other developments affecting executive compensation.

The Consultant met with members of management, including the Chief Executive Officer and Vice President Human Resources, in carrying out these duties, but reported exclusively to our Compensation Committee.

Role of the Chief Executive Officer and Other Executive Officers

Our Compensation Committee considered input from the Chief Executive Officer in determining the individual compensation of each executive officer (other than himself). Mr. Stanley considered external benchmarking information, both company and individual performance, and internal equity in determining his recommendations for executive officer compensation. He made recommendations for base pay adjustments and long-term incentive awards in February 2011 and the following year, February 2012, for annual incentive awards recognizing 2011 performance. Mr. Stanley's own total compensation is determined by the Compensation Committee with the support of the Consultant and approved by all of the independent directors except Mr. Baker using the same considerations as above.

The Vice President Human Resources and her team also provide information to our Compensation Committee to aid the decision-making process including areas such as: individual executives' compensation information, succession potential, organizational considerations, alignment with internal employee programs and Company performance.

Compensation Assessment Tools

At the request of our Compensation Committee, the Consultant annually conducts a benchmarking analysis to use as a reference point for assessing the competitiveness of QEP's executive compensation programs. The Consultant identified an industry peer group of which QEP's asset value and market capitalization approximate the median. The peer group consists of independent exploration and production companies with predominantly U.S. and onshore operations and does not include pipeline, coal, or integrated energy companies. These companies were selected because they represent QEP's marketplace for talent – our key source for recruiting. The Consultant then conducted a benchmarking analysis of the peer group to derive the 25th, 50th, and 75th percentiles for each component of compensation (base salary, target bonus, and long-term incentives) and total compensation for each of our executive officers, including the Named Executive Officers. Our Compensation Committee does not target a specific percentile from this analysis, but uses all the data points as guidance to inform decisions. The peer group used for the 2011 compensation decisions included the following companies:

Cabot Oil & Gas Corporation	Newfield Exploration Company	Quicksilver Resources, Inc.
Cimarex Energy Company	Noble Energy, Inc.	Range Resources Corporation
Denbury Resources Inc.	Petrohawk Energy Corporation*	Southwestern Energy Company
EOG Resources, Inc.	Pioneer Natural Resources Company	Ultra Petroleum Corporation
Forest Oil Corporation	Plains Exploration and Production	Whiting Petroleum Corporation

* Petrohawk was acquired in September 2011; our Committee is considering appropriate replacement companies as part of the 2012 annual peer group review process.

To support specific compensation decisions, our Compensation Committee may also review additional information, including but not limited to stock ownership levels and calculations of potential liabilities upon various termination events.

Timing of Compensation Decisions

Our Compensation Committee conducts its annual executive compensation review at its February meeting. All equity grants approved are effective the same day as the meeting and vest according to a schedule typically spanning the next 3-4 years. Base salary changes and yearly annual incentive awards for the prior year's performance are effective on March 1. From time to time, our Compensation Committee may approve additional compensation actions during the year in the case of promotions, new hires, or other special circumstances. There were no such approvals made affecting a Named Executive Officer's compensation in 2011.

Compensation Elements

The table below identifies each element of our compensation program and the primary role of such element in achieving our compensation objectives.

Compensation Element	Role in Total Compensation
Base Salary	• Provides fixed compensation based on an individual's skills, experience and proficiency, market competitive data, and the relative value of the role within the company
Annual Cash Incentive	• Rewards annual Company and individual performance; • Aligns participants with short-term financial and operational objectives specific to each calendar year; • Motivates participants to meet or exceed internal and external performance expectations; • Communicates the Board's evaluation of annual company performance; and • Recognizes individual contributions to the organization's results.
Long-Term Incentives Performance Share Units Restricted stock Stock options	• Rewards long-term Company performance, directly aligned with shareholder interests; • Provides a strong performance-based equity component • Recognizes and rewards share performance relative to industry peers; • Aligns compensation with sustained long-term value creation; • Allows executives to acquire a meaningful and sustained ownership stake in the Company; and • Fosters executive retention by vesting awards over multiple years.
Benefits Retirement Nonqualified Deferred Compensation Benefits Other (health care, life, disability)	• Provides financial security in the event of various individual risks; and • Maximizes the efficiency of tax-advantaged compensation vehicles.
Termination Benefits	• Provides a competitive level of income protection.

Base Salary

Our Compensation Committee approves base salaries for all officers, including Named Executive Officers, on an annual basis by considering their scope of responsibilities, individual performance, and peer group benchmark data at the 25th, 50th, and 75th percentiles.

The table below reflects the base salaries of our Named Executive Officers at the end of 2010 (determined prior to the spin-off) and the changes approved in February 2011. The total salary paid during 2011 for each of these individuals is included in the section entitled *Compensation Tables – Summary Compensation Table.*

Name	Title	Salary at Spin-off	2011 Salary*	Percent Increase
Mr. Stanley	President and Chief Executive Officer	$720,000	$750,000	4.2%
Mr. Doleshek	Chief Financial Officer	$470,000	$490,000	4.3%
Mr. Neese	Executive Vice President	$375,000	$425,000	13.3%
Mr. Richards	Senior Vice President – Field Services	$260,000	$270,000	3.8%
Mr. Dady	Vice President and General Counsel	$250,000	$315,000	26.0%

* Base salary change was effective March 1, 2011.

Our Compensation Committee approved larger increases for Mr. Neese (13%) and Mr. Dady (26%) as they assumed broader executive roles after our spin-off from Questar in 2010. Mr. Neese assumed greater leadership responsibilities for QEP's exploration and production business as a result of Mr. Stanley's new responsibilities as CEO of QEP. Mr. Dady was General Counsel for a division of Questar and with the spin-off, became Vice President and General Counsel for QEP.

Annual Incentive Program

Our annual incentive program is based on key one-year operational and financial metrics that drive long-term shareholder value. As part of our effort to strengthen the link between pay and performance and improve competitiveness, several changes were made to our annual incentive plan in 2011. The program now allows for differentiation of awards based on individual performance and provides an opportunity for the Compensation Committee to apply discretion when assessing overall company performance. In recognition of post-spin roles and to improve competitiveness within our peer group, the Compensation Committee approved changes to certain executive officers' annual incentive targets as a percentage of 2011 base salary as follows:

Name	2010 Target	2011 Target
Mr. Stanley	90%	100%
Mr. Doleshek	90%	90%
Mr. Neese	70%	85%
Mr. Richards	47.5%	50%
Mr. Dady	40%	60%

The 2011 annual incentive program was based on the following operational and financial performance goals:

Metric	Weight	50% of Target	100% of Target	150% of Target	200% of Target
Adjusted EBITDA(1) $M	45%	$1,251	$1,280	$1,340	$1,400
QEP Proved Developed Finding and Development Cost(2) $/Mcfe	15%	$ 2.51	$ 2.34	$ 2.07	$ 1.80
QEP Production Bcfe	15%	260	266	281	295
Achievement of Strategic Objectives	25%	Qualitative Assessment			

(1) Adjusted EBITDA will be price-indexed to eliminate the impact of commodity prices on the results of the incentive plan.

(2) Proved Developed Finding and Development Cost is defined as: total dollars spent in 2011 on drilling and completion of wells divided by the change in total proved developed reserves from 12/31/10 to 12/31/11, excluding price-related revisions and revisions due to changes in processing arrangements (keep-whole vs. fee-based) and the purchase or sale of any reserves during the year.

Our Compensation Committee chose these metrics because they drive long-term shareholder value. For 2011 performance, our Compensation Committee used the discretionary portion of the annual incentive program to reward the achievement of the following key strategic goals:

- Manage capital investment prudently in response to current low natural gas prices and economic conditions;
- Reduce operating and general and administrative costs without sacrificing safety, long-term efficiency or production;
- Increase oil, condensate and NGL production and reserves relative to gas;
- Effectively start up Blacks Fork II facility;
- Strengthen our Health, Safety and Environmental culture;
- Enhance integration and cooperation across the Company through improved communication and collaboration;
- Complete build out of all QEP functions and processes to support a stand-alone company;
- Enhance our ability to attract, motivate and retain key talent;
- Enhance monthly financial data delivery and analysis; and
- Prepare and respond to unforeseen events and opportunities.

This qualitative assessment of the achievement of strategic objectives affords the Committee the opportunity in the incentive plan to encourage management's efforts in areas that position the company for future success but are less quantifiable.

In addition, our Compensation Committee, in its sole discretion, may adjust (increase or decrease) the cash award otherwise payable to any NEO if the individual's performance during the year warrants an adjustment from the overall company performance level determined from this assessment. Actual 2011 results against the annual incentive program metrics were as follows:

Metric	Weight	Actual 2011 Results	Percent of Target
QEP Resources Adjusted EBITDA(1) $M	**45%**	**$1,405.1(1)**	**200%**
QEP Proved Developed Finding & Development Costs $/Mcfe	15%	$ 2.38(2)	88%
QEP Production Bcfe	**15%**	**275.2**	**131%**
Achievement of Strategic Objectives	25%		90%

(1) Actual Adjusted EBITDA of $1,386 million was price-indexed to eliminate the $19 million impact of commodity prices on the results of the incentive plan.

(2) Actual Proved Developed Finding and Development Costs of $2.07 was adjusted to exclude NGL reserves added in Pinedale that were a result of an intercompany agreement change (keep-whole to fee-based). Without this adjustment, percent of target achieved on this metric would have been 150%.

For the achievement of strategic goals, the Company achieved or exceeded expectations on the majority of the strategic goals, including the safe, on-budget and early completion of the Blacks Fork II cryogenic gas processing plant in western Wyoming, which resulted in a significant increase in NGL production and reserves for QEP Energy, and NGL sales from keep-whole processing in QEP Field Services. However, our results on safety did not meet the Committee's or the Company's expectations. We saw an increase over prior years of key indicators such as the Motor Vehicle Incident Rate. This combination of factors led to the resultant payout of 90% of target for the qualitative assessment.

The overall percent of target earned for the Company was 145%. The Compensation Committee adjusted Mr. Richards' award to reflect Field Services' outstanding performance and contributions during 2011 related to the early startup of the Blacks Fork II processing plant, in addition to the safe, reliable operation of existing facilities. The payout percentage was applied to the targets listed below to arrive at the actual payouts listed in the Non-Equity Incentive Compensation column of the Summary Compensation Table.

Named Executive Officer	Target % of 2011 Base Salaries	Individual Performance	Total Payout % of Target	Annual Incentive Payout*
Mr. Stanley	**100%**	**100%**	**145%**	**$1,087,500**
Mr. Doleshek	90%	100%	145%	$ 639,450
Mr. Neese	**85%**	**100%**	**145%**	**$ 523,813**
Mr. Richards	50%	120%	174%	$ 234,900
Mr. Dady	**60%**	**100%**	**145%**	**$ 274,050**

* The annual incentive payout is calculated by the following formula:
Payout = (base salary) x (target % of base) x (company performance %) x (individual performance %)

Long-Term Incentives

Our long-term incentive program is designed to align executive compensation with a focus on long-term stock price and total shareholder return (TSR) performance, both on an absolute basis and relative to industry peers. For Named Executive Officers, the program consists of the following components:

Long-Term Incentive Component	Weight	Vesting/Mechanics
Long-Term Cash Incentive Plan/ Performance Share Units	⅓	• Value of award is denominated into performance share units that track the Company's stock price • Performance units cliff vest at the end of a three year performance period based on relative shareholder return • Upon vesting, the units are paid to executives in cash
Stock Options	⅓	• Value of award is denominated into stock options based on Black-Scholes methodology • Strike price is determined using the closing price on the date of grant • Vests ratably over a 3-year period • 7-year term (expires 7 years from grant date)
Restricted Stock	⅓	• Value of award is denominated into shares based on the closing price on the date of grant • Vests ratably over a 3-year period • Dividends are paid on unvested shares

Long-Term Cash Incentive Plan (LTCIP)

Of the total long-term incentive awarded annually to each executive, one-third is performance share units granted under our Long-Term Cash Incentive Plan (LTCIP). Performance share units are stock-denominated awards that are earned over a three-year performance cycle based on the Company's total shareholder return (TSR) over the performance period compared to the TSR of a group of peer companies over the same period. Total shareholder return combines share price appreciation and dividends paid to determine the total return to the shareholder. For the 2011-2013 cycle granted in February 2011, the peer group used was consistent with that used for compensation benchmarking listed in the *Compensation Assessment Tools* section. The payout scale is detailed in the following table, with interpolation between each point.

QEP's Percentile Rank in Peer Group	Percentage Payout
90th Percentile or Above	200%
70th Percentile	150%
50th Percentile	100%
30th Percentile	50%
Below 30th Percentile	0%

The actual cash payout under the plan at the end of the performance period is calculated using the following formula:

Payout = (number of performance share units awarded) x (percentage payout) x (average stock price in the fourth quarter of the final year of the performance period)

In 2011, our Compensation Committee did not make a determination regarding achievement of performance goals under prior grants of performance share units, as no previous awards were outstanding. Awards granted to executives under the Questar Corporation Long-Term Cash Incentive Plan (Questar LTCIP) for the 2009 to 2011 and 2010 to 2012 performance periods were converted on the date of the spin-off from awards payable in cash under the Questar LTCIP to awards of restricted shares of our common stock granted under our LTSIP (LTCIP Conversion Awards).

Long-Term Stock Incentive Plan (LTSIP)

Of the total long-term incentive awarded annually to each executive, one-third is granted in stock options and one-third in restricted stock under our LTSIP. These equity incentive tools align executive compensation directly with stock price performance. The vesting schedule of the grants extends over a three-year period, with one-third of the shares vesting each year. The shares do not automatically vest upon retirement. In the event of a change in control, all unvested shares vest immediately.

QEP policies do not permit the backdating of stock options. As set forth in the LTSIP, the Compensation Committee (or, in the case of the chief executive officer, non-employee directors) sets the option strike price at the time the option is granted, and that strike price cannot be less than the closing price of our common stock on the date of such grant.

Determination of Long-Term Incentive Awards

In determining long-term incentive award values, our Compensation Committee considered the market data provided by the Consultant as well as individual and business performance, proficiency and succession potential. Mr. Stanley's award recognized his promotion to Chief Executive Officer, the success of the spin-off, completion of key strategic goals and outstanding operations performance in 2010. The long-term incentive award for Mr. Doleshek also recognized the success of the spin-off and outstanding operational performance in 2010, as well as completion of a public debt financing and the effectiveness of the Company's commodity price risk management program. Similar to base pay decisions, the long-term incentive awards for Mr. Neese and Mr. Dady were based on positioning their compensation for their new post-spin broader executive roles. Mr. Richards' grant maintains a competitive position for his role. The Named Executive Officers each received the following grants in February 2011:

Named Executive Officer	Number of Stock Options	Number of Shares of Restricted Stock	Performance Share Units	Estimated Total Value at Grant Date (millions)*
Mr. Stanley	63,588	32,421	32,421	$3.80
Mr. Doleshek	30,958	15,784	15,784	$1.85
Mr. Neese	27,611	14,078	14,078	$1.65
Mr. Richards	9,371	4,778	4,778	$0.56
Mr. Dady	7,531	3,840	3,840	$0.45

* Stock option grant date values are estimated based on the Black-Scholes methodology with assumptions determined in February 2011.

Benefits

Our Named Executive Officers are eligible for the retirement plans described below. We believe these plans help us attract and retain talented employees and are competitive in the exploration and production industry. These benefits are similar to the benefits provided to all QEP employees; we do not provide any special benefits to our executive officers other than the restoration of benefits lost due to compensation limits imposed by the Internal Revenue Code (the Code).

- QEP Resources, Inc. Employee Investment Plan – a 401(k) qualified defined contribution plan that allows deferral up to limits imposed by the Code with a company match of 100% of the employee's contributions up to 6% of eligible compensation.

- QEP Resources, Inc. Retirement Plan – a tax qualified defined benefit pension plan pursuant to which our named executive officers have accrued benefits that were frozen as of June 30, 2010.

- QEP Deferred Compensation Wrap Plan – a nonqualified plan that provides for individuals to defer additional amounts above IRC caps and to receive the standard company match up to 6% of salary above the Code caps as if they were participating in the QEP 401(k) plan.

- QEP Supplemental Executive Retirement Plan – a nonqualified plan that restores benefits lost in the QEP Retirement Plan due to IRC limitations on compensation.

More detail on each of these plans is available in the *Compensation Tables* section.

In addition to the retirement benefits above, we also provide other benefits identical to those provided to all other employees, such as medical, dental, and vision insurance, a cafeteria plan (which includes flexible health-care spending account and dependent-care spending account features), employer-paid basic life insurance (providing two-times base salary coverage up to a maximum of $750,000 as of 7/1/11), employer-paid accidental death & dismemberment (one-times base salary up to a maximum of $750,000 as of 7/1/11), employee-paid supplemental life insurance (for up to four-times base salary, but not to exceed $1,000,000), employer-paid dependent life insurance, business-travel accident insurance, voluntary accident insurance, long-term disability and short-term disability insurance, paid time off, paid holidays and an employee assistance program.

Severance Protections

The Named Executive Officers are entitled to certain benefits upon termination as provided in our equity plans and the QEP Resources, Inc. Executive Severance Compensation Plan (the QEP Severance Plan). More detail on potential payments upon various termination events is available in the section entitled *Potential Payments upon Termination or Change in Control.*

Employment Agreements – Mr. Stanley and Mr. Doleshek are both subject to employment agreements that help ensure the retention of our top two officers and provide additional severance protections not available to other officers. These agreements specify the terms of their employment, including minimum participation in all compensation elements and severance protections, and are described in more detail in the section entitled *Compensation Tables – Employment Agreements.* These agreements expire in June 2013.

Equity Plans – As described in the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan and the applicable award agreements, all long-term incentive awards vest upon a change in control. This provision is aligned with current market practices, serves as a retention tool leading up to a change in control, and simplifies the transition of these plans upon a change in control.

QEP Executive Severance Plan – The QEP Executive Severance Plan is a "double-trigger" plan that provides for benefits upon qualifying terminations of employment occurring on or within three years following a change in control of QEP. We have recently amended this plan to remove the excise tax gross-ups based on feedback from investors and to align the Plan with evolving governance standards. Our Compensation Committee believes that these arrangements assist the Company in attracting and retaining executive talent and in aligning management's interests with shareholders in the event of a change in control. The plan is described, and estimates of payments to the named executives as of December 31, 2011, are set forth in the section entitled *Potential Payments upon Termination or Change in Control.*

Other Executive Compensation Matters

Executive Share Ownership Requirements

We have established stock ownership guidelines for executive officers with the goal of promoting ownership of our common stock and aligning the interests of our executive officers with those of our shareholders. The ownership guidelines are currently established at the following minimum levels:

Named Executive Officer	Guideline	Ownership Status as of 12/31/2011
Mr. Stanley(1)	6x base salary	Exceeds
Mr. Doleshek(1)	3x base salary	Exceeds
Other Named Executive Officers	2x base salary	Exceeds

(1) The stock ownership guidelines for Messrs. Stanley and Doleshek are set forth in their respective employment agreements.

Our executives are required to achieve the applicable level of stock ownership within five years of the date the person first becomes an executive officer. Shares that count towards satisfaction of the guidelines include shares owned outright by the executive, restricted shares, shares held in the Employee Investment Plan and phantom stock units attributable to deferred compensation under the QEP Deferred Compensation Wrap Plan.

Tax and Accounting Considerations

Our Compensation Committee considers tax and accounting rules and regulations when structuring the executive compensation paid to our Named Executive Officers, including the following:

- Section 162(m) – Section 162(m) of the Code, precludes us from deducting for tax purposes compensation paid in excess of $1,000,000 per year to any named executive officer listed in the Summary Compensation Table (other than our chief financial officer), except performance-based compensation. Our Compensation Committee may award compensation that is not deductible if, in our Compensation Committee's judgment, doing so is necessary to achieve an appropriate compensation structure. While base salary and time-based restricted stock, by their nature, do not qualify as performance-based compensation, our Compensation Committee has structured our Long-Term Cash Incentive Plan and annual incentive program with the intent that they qualify as performance-based compensation under the Code. For our annual incentive program, we incorporate a financial metric to fund an overall pool, such that awards granted under the annual incentive program are intended to qualify as performance-based compensation under the Code.[2]
- Section 409A – Section 409A of the Code requires that "nonqualified deferred compensation" be deferred and paid under plans or arrangements that satisfy the requirements of the statute with respect to the timing of deferral elections, timing of payments and certain other matters. Failure to satisfy these requirements can expose our employees and other service providers to accelerated income tax liabilities and penalty taxes and interest on their vested compensation under such plans. Our Compensation Committee endeavors to structure executive officers' compensation in a manner that is either compliant with, or exempt from the application of, Section 409A of the Code.

[2] For 2011, the pool was established as 1% of EBITDA. EBITDA is a non-GAAP measure. Management defines EBITDA as net income before the following items: interest and other income, income taxes, interest expense, and depreciation, depletion and amortization. EBITDA for purposes of determining the pool available under our AMIP II differs from the Adjusted EBITDA referred to above and in our Annual Report on Form 10-K. Adjusted EBITDA is, however, used as a metric to determine amounts payable under our Annual Incentive Plan.

- Fair Value of Stock-Based Payments – Awards of stock options and restricted stock under LTSIP and awards of performance share units under the LTCIP are accounted for under FASB ASC Topic 718 (formerly referred to as SFAS No. 123(R)). FASB ASC Topic 718 requires the recognition of expense for the fair value of stock-based payments. Our Compensation Committee considers the accounting impact in evaluating QEP's executive compensation programs.

Compensation Risk Assessment

We regularly evaluate the major risks to our business, including how risks taken by management could impact the value of executive compensation. Our Compensation Committee reviewed a risk assessment completed by the Consultant of the Company's executive and non-executive compensation programs. Based on such review, our Compensation Committee believes that while there are certain risks inherent in the nature of the Company's business, the Company's compensation program does not encourage our executives or our non-executive employees to take inappropriate or excessive risks and is not reasonably likely to have a material adverse effect on the Company. The risk-mitigating factors considered by our Compensation Committee included the following:

- an appropriate balance of operating and financial performance measures;
- an appropriate balance of fixed and at-risk compensation components;
- a balanced mix of cash and equity, with significant weighing on long-term incentive awards;
- significant stock ownership requirements for executives and a hedging policy;
- extended three-year vesting schedules on equity grants; and
- caps and defined thresholds for payout on incentive awards.

Our Compensation Committee believes that these factors encourage all of our employees to focus on QEP's sustained long-term performance.

Derivatives Trading and Hedging Prohibition

The Company has a policy that prohibits directors, officers and employees from engaging in derivative transactions involving QEP stock for any purpose, including short-term trading, short sales, options trading, trading on margin, and hedging.

Clawback of Compensation

Management plans to implement a clawback provision for incentive compensation (triggered upon specified restatements of financial statements), subject to Compensation Committee approval, once the SEC adopts new regulations implementing the requirements of the Dodd-Frank Act regarding clawbacks.

Succession Planning

The Compensation Committee conducts a succession planning program that involves assessment throughout the organization of high potential employees and readiness of potential successors to key roles. Our Compensation Committee annually conducts a review with specific focus on the CEO and his direct reports. Our Compensation Committee views this as a critical process to ensure continuity of our business and to provide challenging and rewarding career opportunities for our employees.

COMPENSATION TABLES

SUMMARY COMPENSATION TABLE

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($)(3) (f)	Non-Equity Incentive Plan Compen-sation ($)(4) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)(6) (h)	All Other Compen-sation ($)(7) (i)	Total ($)(8) (j)
Charles B. Stanley	2011	745,000	0	2,533,377(1)	1,266,673	1,087,500	1,078,612	23,200	6,734,362
President & Chief	2010	720,000	0	4,084,441(2)	690,060	1,699,792	633,425	42,392	7,870,110
Executive Officer	2009	700,000	0	566,080	902,880	1,285,699	417,623	23,987	3,896,269
Richard J. Doleshek	2011	486,667	0	1,233,362(1)	616,683	639,450	290,528	48,200	3,314,890
Executive Vice	2010	466,667	0	2,397,220(2)	333,900	846,000	164,826	11,760	4,220,373
President & Chief	2009	293,365	0	2,031,600	868,000	622,688	44,457	349,726	4,209,836
Financial Officer									
Jay B. Neese	2011	416,667	0	1,100,055(1)	550,011	523,813	1,202,656	38,969	3,832,170
Executive Vice	2010	375,000	0	2,059,735(2)	333,900	776,655	572,177	35,837	4,153,304
President	2009	330,000	0	0	668,800	496,739	361,794	28,544	1,885,877
Perry H. Richards	2011	268,333	0	373,353(1)	186,670	234,900	532,043	33,584	1,628,884
Senior Vice President,	2010	260,000	0	454,884(2)	166,950	322,464	295,203	19,700	1,519,201
QEP Field Services	2009	232,500	0	176,900	209,000	239,011	176,193	19,371	1,052,975
Eric L. Dady	2011	304,167	0	300,058(1)	150,018	274,050	530,032	34,065	1,592,389
Vice President &	2010	242,498	0	281,311(2)	0	212,071	224,278	23,738	983,896
General Counsel	2009	225,756	0	28,304	83,600	125,865	167,265	19,241	654,173

(1) The amounts in column E for 2011 include the 2011 grants under the Long Term Cash Incentive Plan (LTCIP). Awards are denominated in performance share units, cliff vest in 3 years and are paid in cash. In previous years, these awards were shown at payout in column G because the awards were not denominated in performance share units but instead included a "stock price appreciation" factor. Due to this change in the program, the awards are disclosed at grant in column E rather than at payout in column G. Stock awards include performance share units granted under the LTCIP and restricted stock granted under the LTSIP at the grant date fair values below:

Name	Performance Share Units ($)	Restricted Stock ($)
Charles B. Stanley	1,266,688	1,266,688
Richard J. Doleshek	616,681	616,681
Jay B. Neese	550,027	550,027
Perry H. Richards	186,676	186,676
Eric L. Dady	150,029	150,029

(2) The amounts in column E for 2010 were higher due to the LTCIP Conversion Awards and spin-off recognition awards. LTCIP Conversion Awards were the conversion at spin-off of outstanding long-term cash incentive plan awards under the Questar LTCIP plan to restricted stock under the terms of our LTSIP. Spin-off recognition awards were grants of restricted stock made to reward the effort certain executives put forth to execute the spin-off transaction.

(3) The dollar amount indicated in column F is the aggregate grant date fair value computed in accordance FASB ASC Topic 718, excluding the effect of estimated forfeitures. The assumptions used in determining the grant date fair value of these awards are described in Note 10 to the consolidated financial statements included in Item 8 of Part II of the our 2011 Form 10-K.

(4) The amounts in column G reflect the cash incentive awards for 2011 that were determined by the Compensation Committee and paid out in February 2012. These awards are discussed in further detail in the Compensation Discussion and Analysis.
(5) The amounts in Column H represent the actuarial increase in the present value of the named executive officer's benefits under the QEP Pension Plan and the Supplemental Executive Retirement Plan (SERP). These estimates are determined using interest-rate and mortality-rate assumptions consistent with those used in the consolidated financial statements included in Item 8 of Part II of the our 2011 Form 10-K.
(6) The amounts in Column H do not include any Nonqualified Deferred Compensation earnings because such earnings, as reflected in the Nonqualified Deferred Compensation table column (d), do not consist of any above-market or preferential earnings.
(7) Items included in column J (All Other Compensation) are detailed below and include an officer allowance of $8,500 based on current market practices to offset the cost of tax preparation, financial planning, and other expenses:

Name	QEP 401(k) Plan Employer Match ($)	Paid Time-Off Sold ($)	Officer Allowance ($)	Relocation Expense Reimbursement ($)	Total
Charles B. Stanley	$14,700	n/a	$8,500		$23,200
Richard J. Doleshek	$14,700	n/a	$8,500	$25,000	$48,200
Jay B. Neese	$14,700	$15,769	$8,500		$38,969
Perry H. Richards	$14,700	$10,384	$8,500		$33,584
Eric L. Dady	$14,700	$10,865	$8,500		$34,065

(8) As reflected in the Summary Compensation Table above, the salary received by each of our named executive officers as a percentage of their respective total compensation during the year indicated was as follows:

Name	Year	Percentage of Total Compensation
Charles B. Stanley	2011	11.1%
	2010	9.1%
	2009	18.0%
Richard J. Doleshek	2011	14.7%
	2010	11.1%
	2009	7.0%
Jay B. Neese	2011	10.9%
	2010	9.0%
	2009	17.5%
Perry H. Richards	2011	16.5%
	2010	17.1%
	2009	22.0%
Eric L. Dady	2011	19.1%
	2010	24.6%
	2009	34.5%

Employment Agreements

We have employment agreements with Charles B. Stanley, our President and Chief Executive Officer, and Richard J. Doleshek, our Executive Vice President, Chief Financial Officer and Treasurer. The terms of these agreements are summarized below.

Mr. Stanley

Under his employment agreement, Mr. Stanley serves as our President and Chief Executive Officer and as a member of our Board. His employment agreement was effective July 1, 2010, and has a term of three years, unless terminated earlier by QEP or Mr. Stanley in accordance with the provisions therein. Mr. Stanley receives a minimum annual base salary of $720,000, which is reviewed annually by the Compensation Committee and may be increased but not reduced. Mr. Stanley is eligible to participate in the annual incentive plan, under which his target bonus will equal a minimum of 90% of his annual base salary. Mr. Stanley is also entitled to participate in the LTCIP, under which his target bonus will be at least equal to that provided to any other officer. Mr. Stanley is also entitled to other benefits, including participation in our 401(k) plan, health and welfare plans, executive severance plan, deferred compensation plan, and the SERP. Mr. Stanley is entitled to receive equity awards at least equal to that provided to any other QEP officer, which equity awards will permit Mr. Stanley to exercise any vested options for at least 30 days following the termination of his employment, unless a longer period is otherwise specified. Mr. Stanley is eligible to receive certain payments upon termination or change of control. These payments are described in the section *Potential Payments upon Termination or Change in Control.*

Mr. Doleshek

Under his employment agreement, Mr. Doleshek serves as the Executive Vice President, Chief Financial Officer and Treasurer of QEP. His employment agreement was effective July 1, 2010, and has a term of three years, unless terminated earlier by QEP or Mr. Doleshek in accordance with the provisions therein. Mr. Doleshek receives a minimum annual base salary of $470,000, which is reviewed annually and may be increased but not reduced. Mr. Doleshek is eligible to participate in the annual incentive program, under which his target bonus will equal a minimum of 90% of his annual base salary. Mr. Doleshek is also entitled to participate in our LTCIP, under which his target bonus will not be less than $500,000. Mr. Doleshek is also entitled to other benefits, including participation in our 401(k) plan, health and welfare plans, executive severance plan, deferred compensation plan, and the SERP. Mr. Doleshek may receive equity awards to be granted in the Compensation Committee's sole discretion. Mr. Doleshek is eligible to receive certain payments upon termination or change of control. These payments are described in the section *Potential Payments upon Termination or Change in Control.*

GRANTS OF PLAN-BASED AWARDS FOR 2011

This table shows the plan-based awards granted to the named executive officers during 2011. For non-equity and equity incentive plans, it sets forth the ranges of possible awards. For stock awards, the table shows the number of shares or option shares granted and the grant date fair values of those awards.

		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	All Other Option Awards: Number of Securities Under-lying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock & Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold ($) (f)	Target ($) (g)	Maximum ($) (h)	(#) (i)	(#) (j)	($/share) (k)(5)	($) (l)
Charles B. Stanley	**Feb. 25, 2011**	**56,250**	**750,000**	**1,500,000**				**0**	**0**		**0**
	Feb. 25, 2011(2)				**633,344**	**1,266,688**	**2,533,377**	**0**	**0**		**0**
	Feb. 25, 2011(3)	**0**	**0**	**0**				**0**	**63,588**	**39.07**	**1,266,673**
	Feb. 25, 2011(4)	**0**	**0**	**0**				**32,421**	**0**		**1,266,688**
Richard J. Doleshek	Feb. 25, 2011	33,075	441,000	882,000				0	0		0
	Feb. 25, 2011(2)				308,340	616,681	1,233,362	0	0		0
	Feb. 25, 2011(3)	0	0	0				0	30,958	39.07	616,683
	Feb. 25, 2011(4)	0	0	0				15,784	0		616,681
Jay B. Neese	**Feb. 25, 2011**	**27,094**	**361,250**	**722,500**				**0**	**0**		**0**
	Feb. 25, 2011(2)				**275,014**	**550,027**	**1,100,055**	**0**	**0**		**0**
	Feb. 25, 2011(3)	**0**	**0**	**0**				**0**	**27,611**	**39.07**	**550,011**
	Feb. 25, 2011(4)	**0**	**0**	**0**				**14,078**	**0**		**550,027**
Perry H. Richards	Feb. 25, 2011	10,125	135,000	270,000				0	0		0
	Feb. 25, 2011(2)				93,338	186,676	373,353	0	0		0
	Feb. 25, 2011(3)	0	0	0				0	9,371	39.07	186,670
	Feb. 25, 2011(4)	0	0	0				4,778	0		186,676
Eric L. Dady	**Feb. 25, 2011**	**14,175**	**189,000**	**378,000**				**0**	**0**		**0**
	Feb. 25, 2011(2)				**75,014**	**150,029**	**300,058**	**0**	**0**		**0**
	Feb. 25, 2011(3)	**0**	**0**	**0**				**0**	**7,531**	**39.07**	**150,018**
	Feb. 25, 2011(4)	**0**	**0**	**0**				**3,840**	**0**		**150,029**

(1) The amounts included in these columns reflect estimated future cash payouts under our annual incentive program based on actual base salaries for 2011. If threshold levels of performance are not met, then the payout can be zero. Actual incentive payouts are reflected in the "Non-Equity Incentive Plan Compensation" column of the Summary Compensation Table.

(2) This row represents the opportunity under the LTCIP.

(3) This row shows options granted during 2011 pursuant to the LTSIP.

(4) This row shows grants of restricted stock during 2011 pursuant to the LTSIP.

(5) This price represents the closing price of QEP common stock on February 25, 2011.

Amounts payable under our non-equity long-term cash incentive plan and our long-term stock incentive plan are determined based on performance criteria set forth in the Compensation Discussion and Analysis.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2011

This table shows outstanding equity awards for the named executive officers. All values shown are as of December 31, 2011.

	Option Awards				Stock Awards			
					Restricted Stock		Performance Share Units	
Name (a)	Shares of Common Stock Underlying Unexercised Options Exercisable (#) (b)	Shares of Common Stock Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Shares or Units of Stock that have not Vested (#) (g)	Market Value of Shares or Units of Stock that have not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that have not Vested (#)(11) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that have not Vested ($) (j)
Charles B. Stanley	172,000	0	8.12	01/13/12	12,000(5)	351,600	32,421	949,935
	112,000	0	7.78	02/11/12	34,633(1)	1,014,747		
	150,000	0	9.19	02/11/13	18,666(2)	546,914		
	200,000	0	26.14	10/24/12	40,514(6)	1,187,060		
	60,000	0	27.84	02/13/15	30,706(7)	899,686		
	72,000	36,000(1)	23.98	02/12/16	32,421(3)	949,935		
	20,667	41,333(2)	27.55	03/05/17				
	0	63,588(3)	39.07	02/25/18				
Richard J. Doleshek	0	100,000(4)	22.95	05/07/16	20,000(8)	586,000	15,784	462,471
	10,000	20,000(2)	27.55	03/05/17	10,000(2)	293,000		
	0	30,958(3)	39.07	02/25/18	40,514(6)	1,187,060		
					20,471(7)	599,800		
					15,784(3)	462,471		
Jay B. Neese	17,910	0	9.19	02/11/13	750(9)	21,975	14,078	412,485
	53,333	26,667(1)	23.98	03/05/16	3,333(5)	97,657		
	10,000	20,000(2)	27.55	03/05/17	9,000(2)	263,700		
		27,611(3)	39.07	02/25/18	12,209(1)	357,724		
					22,283(6)	652,892		
					17,059(7)	499,829		
					14,078(3)	412,485		
Perry H. Richards	3,000	0	9.19	02/11/13	2,000(5)	58,600	4,778	139,995
	16,667	8,333(1)	23.98	03/05/16	1,666(1)	48,814		
	5,000	10,000(2)	27.55	03/05/17	5,000(2)	146,500		
	0	9,371(3)	39.07	02/25/18	5,118(7)	149,957		
					4,778(3)	139,995		
Eric L. Dady	6,667	3,333(1)	23.98	03/05/16	300(10)	8,790	3,840	112,512
	0	7,531(3)	39.07	02/25/18	333(5)	9,757		
					266(1)	7,794		
					1,333(2)	39,057		
					6,824(7)	199,943		
					3,840(3)	112,512		

(1) These shares vested on March 5, 2012.

(2) 50% of these shares vested on March 5, 2012 and 50% will vest on March 5, 2013.

(3) 33.3% of these shares vested on March 5, 2012; 33.3% will vest on March 5, 2013; and 33.3% will vest on March 5, 2014.

(4) 100% of these shares will vest on May 7, 2012.

(5) These shares vested on February 12, 2012.

(6) These shares will vest on March 5, 2013.
(7) 33.3% of these shares will vest on September 5, 2012; 33.3% will vest on September 5, 2013; and 33.3% will vest on September 5, 2014.
(8) These shares will vest on May 7, 2012.
(9) These shares will vest on October 30, 2012.
(10) These shares will vest on August 31, 2012.
(11) These amounts represent the target number of performance share units awarded under the LTCIP. Each performance share unit represents a contingent right to receive the fair market value of one share of QEP common stock. The actual number of shares that may be earned (and, therefore, the actual cash payout amount) will range from 0% to 200% of the number of performance share units awarded, depending on QEP's relative total shareholder return in comparison to a peer group of companies during the three-year period ending December 31, 2014.

OPTION EXERCISES AND STOCK VESTED IN 2011

Name (a)	Stock Awards Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($)(1) (e)
Charles B. Stanley	31,999	1,225,828
Richard J. Doleshek	25,000	1,028,750
Jay B. Neese	3,333	128,354
Perry H. Richards	6,167	235,658
Eric L. Dady	1,567	58,944

(1) The value realized equals the market value on the vesting date multiplied by the number of shares vested.

Retirement Benefits

The QEP Resources, Inc. Employee Investment Plan (EIP) is a 401(k) Plan that allows employees to defer and contribute a portion of their compensation up to the annual IRS limit ($245,000 in 2011). The Company provides matching contributions on 100% of an employee's contributions up to 6% of eligible compensation. The employee deferrals and matching contributions are invested, as directed by the participant, in mutual funds or other alternatives, including QEP common stock.

The QEP Resources, Inc. Retirement Plan is a defined benefit pension plan. At the time of the spin-off, the assets and liabilities held in trust attributable to active QEP employees who were participants in the Questar Retirement Plan were apportioned to the trust of the new QEP Retirement Plan. As of the spin-off date, the named executive officers who participated in the Questar Retirement Plan had their benefits frozen and ceased to accrue benefits under the new QEP Retirement Plan. Instead, following the spin-off, each named executive officer receives all future retirement plan benefits under the SERP. The benefit under the SERP approximates the retirement benefit the plan participants would have received under the QEP Retirement Plan had they remained eligible to participate in such plan and continued to accrue benefits under the plan following the spin-off. The SERP is described below.

Nonqualified Retirement Plans

The Compensation Committee believes that competitive retirement planning programs significantly strengthen our ability to attract and retain executive talent in our industry. QEP established nonqualified retirement plans for the benefit of named executive officers and certain other QEP employees. QEP has two nonqualified retirement plans: the Deferred Compensation Wrap Plan and the SERP.

Deferred Compensation Wrap Plan. QEP allows officers, along with certain other key employees, to defer the receipt of compensation under the Deferred Compensation Wrap Plan. The Wrap Plan includes both a Deferred Compensation Program and a 401(k) Supplemental Program.

Deferred Compensation Program of the Wrap Plan. This Program allows officers and certain key employees to defer taxable income and provide for future financial needs. Eligible employees may defer a portion of their base salaries and cash bonuses for a maximum of ten years after termination of employment. Participants select their investments from a variety of investment options, including QEP phantom shares and an array of mutual funds. Gains and losses on the deferred amounts are tracked against participant-selected investments. A specified percentage of amounts deferred under this program may receive a matching contribution.

401(k) Supplemental Program of the Wrap Plan. This Program allows officers and certain key employees whose compensation exceeds the IRS Limit to defer up to 6% of their salaries in excess of the IRS Limit and to receive a company matching contribution on this deferred amount as if that amount had been invested in the QEP Employee Investment Plan (EIP) / 401(k) Plan. Participant gains and losses on the deferred amounts are tracked against participant-selected investments.

Supplemental Executive Retirement Plan

The named executive officers also participate in the SERP, which generally provides highly compensated employees with supplemental retirement benefits to compensate for the limitations imposed by federal tax laws on benefits payable from the tax-qualified defined benefit pension plan. Participation in the SERP is limited to eligible individuals who have (i) an accrued benefit under the QEP Retirement Plan, and (ii) received or are expected to receive compensation in excess of the limit imposed by the Internal Revenue Service for compensation that may be taken into account for purposes of providing benefits under a tax-qualified pension plan ($245,000 in 2011). For any individuals who became participants in the SERP after the spin-off date, the SERP generally provides benefits equal to the difference between the benefits payable under the QEP Retirement Plan and the benefits that would be payable under such plan if the limits on the annual compensation were not applicable and if the participant had not voluntarily chosen to defer any compensation under the terms of the Wrap Plan.

Upon the spin-off, the qualified and non-qualified retirement plan benefits for active QEP employees who participated in the Questar SERP (Transferred SERP Participants) were transferred to the QEP Retirement Plan and SERP respectively. Their qualified benefits under the QEP Retirement Plan were frozen as of the Spin-off date. All retirement plan benefits earned after the Spin-off date for transferred SERP participants will be accrued in the SERP. Benefits in the SERP will be calculated as follows: the total retirement benefit based on the benefit formula under the QEP Retirement Plan (including compensation in excess of the IRS Limit and any deferred compensation), less the (frozen) benefit payable to the participant under the QEP Retirement Plan.

PENSION BENEFITS

Name (a)	Plan(1) (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($)(3) (d)
Charles B. Stanley	**QEP Retirement Plan**	**8.5(2)**	**298,498**
	SERP	**10**	**2,829,724**
Richard J. Doleshek	QEP Retirement Plan	1(2)	36,518
	SERP	3	463,294
Jay B. Neese(4)	**QEP Retirement Plan**	**32(2)**	**998,511**
	SERP	**34**	**2,664,081**
Perry H. Richards	QEP Retirement Plan	26(2)	809,525
	SERP	28	930,343
Eric L. Dady	**QEP Retirement Plan**	**16(2)**	**726,267**
	SERP	**18**	**802,232**

(1) The named executive officers' accrued retirement plan benefits as of 6/30/10 are frozen. Instead of continued participation in the QEP Retirement Plan, the named executive officers accrue all future benefits after 06/30/10 in our SERP.

(2) This number reflects years of service before participation in the QEP Retirement Plan was frozen.

(3) The Present Value of Accumulated Benefit amounts provided in the table are based on the retirement plan benefits accrued through December 31, 2011, assuming that such benefits are paid in the same form as reflected in the accounting valuation. The benefits are assumed to commence at age 62, the earliest age at which a participant may retire under the plan without any benefit reduction due to age. All pre-retirement decrements such as pre-retirement mortality and terminations have been ignored for the purposes of these calculations. The interest rate used for discounting payments back to December 31, 2011, is 4.7%.

(4) Mr. Neese has a supplemental retirement benefit due to a change in Questar vacation policy in 1997. These benefits are frozen and include $6,923 for Mr. Neese.

NONQUALIFIED DEFERRED COMPENSATION

Name (a)	Executive Contributions in Last FY ($)(1)(2) (b)	Company Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($)(3) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (F)
Charles B. Stanley	**135,855**	**107,655**	**(370,425)**	**0**	**1,668,954**
Richard J. Doleshek	65,210	65,210	(40,165)	0	208,272
Jay B. Neese	**132,069**	**41,643**	**(140,698)**	**0**	**638,829**
Perry H. Richards	16,178	16,178	(16,398)	0	139,278
Eric L. Dady	**36,409**	**16,105**	**(17,523)**	**0**	**173,845**

(1) The named executive officers automatically participated in the QEP 401(k) Supplemental Program of the Wrap Plan when their compensation exceeded the IRS Limit. Six percent of qualified compensation in excess of the IRS Limit is treated as if contributed to the QEP 401(k) Plan and receives the applicable employer match provided for in the QEP 401(k) Plan.

(2) In 2011, Messrs. Stanley, Neese and Dady each deferred compensation under the Deferred Compensation Program of the Wrap Plan. Under the terms of this program, an employee may elect to defer from $5,000 to 50% of annual compensation. Six percent of any compensation deferred receives a Company match as if contributed to the QEP 401(k) Plan.

(3) Aggregate earnings are not included in the Summary Compensation Table because they do not consist of any above-market or preferential earnings.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

Payments upon Termination to Executives with Employment Contracts

The Board entered into employment agreements with Messrs. Stanley and Doleshek to help ensure their retention and to provide additional severance protection not available to other officers. The following table outlines the determination of payments to Messrs. Stanley and Doleshek pursuant to their employment agreements under various termination scenarios (other than in connection with a change in control, which is addressed separately below).

Compensation Component	Termination for Cause or Resignation	Death or Disability	Termination without Cause or Resignation for Good Reason	Retirement
Cash payments	Earned but unpaid base salary and paid time-off benefits	One month salary + earned but unpaid base salary and paid time-off benefits	3x base salary + 3x actual prior year annual incentive paid + earned but unpaid base salary and paid time-off benefits	Earned but unpaid base salary and paid time-off benefits
Annual Incentive	Forfeit	Target incentive payment	Forfeit	Prorated award
Equity Awards	Forfeit unvested equity	Accelerated vesting of all unvested awards	Accelerated vesting of all unvested awards	Forfeit unvested equity
LTCIP	Forfeit outstanding awards	Payment at target of any outstanding awards	Forfeit outstanding awards	Prorated award

Under the employment agreements, "cause" means any of the following: (a) conviction of a felony or of a misdemeanor involving fraud, dishonesty or moral turpitude, or (b) willful or intentional material breach of the agreement that results in financial detriment that is material to the Company and its affiliates taken as a whole.

For purposes of clause (b), "cause" does not include any one or more of the following: (i) bad judgment, (ii) negligence, or (iii) any act or omission that the executive believed in good faith to have been in or not opposed to the interest of the Company (without intent of the executive to gain, directly or indirectly, a profit to which he was not legally entitled), or (iv) any act or omission of which any member of the Board who is not a party to such act or omission has had actual knowledge for at least three months. "Good reason" means any of the following events or conditions occur without the executive's written consent and remain in effect after notice has been provided by the executive to the Company of such event or condition and the expiration of a 30 day cure period: (i) a material diminution in the executive's base compensation; (ii) a material diminution in the executive's authority, duties, or responsibility; (iii) a material change in the geographic location at which executive performs services; or (iv) any other action or inaction that constitutes a material breach by the Company or its subsidiaries of the agreement.

The following table sets forth the estimated payments to Messrs. Stanley and Doleshek pursuant to their employment agreements under various termination scenarios. The table assumes the termination date occurred on December 31, 2011.

Name and Compensation Component	Termination for Cause or Resignation	Death or Disability	Termination without Cause or Resignation for Good Reason	Retirement
Charles B. Stanley				
Cash payments	$111,659	$ 174,159	$ 6,249,035	n/a (1)
Annual Incentive	$ 0	$ 750,000	$ 0	n/a (1)
Equity Awards	$ 0	$6,512,706	$ 6,512,706	n/a (1)
LTCIP	$ 0	$ 949,935	$ 0	n/a (1)
Total	$111,659	$8,386,800	$12,761,741	n/a (1)
Richard J. Doleshek				
Cash payments	$ 70,123	$ 110,957	$ 4,078,123	n/a (1)
Annual Incentive	$ 0	$ 441,000	$ 0	n/a (1)
Equity Awards	$ 0	$5,424,332	$ 5,424,332	n/a (1)
LTCIP	$ 0	$ 462,471	$ 0	n/a (1)
Total	$ 70,123	$6,438,760	$ 9,502,455	n/a (1)

(1) Messrs. Stanley and Doleshek are not yet eligible to retire.

Payments upon Termination to Executives without Employment Contracts

Messrs. Neese, Richards and Dady do not have employment contracts. Therefore, any payments due to them upon termination would be calculated pursuant to the underlying plans and terms of the award agreements. The table below outlines the determination of payments due to executives without contracts upon termination under various scenarios (other than in connection with a change in control, which is addressed separately below).

Compensation Component	Termination for Cause or Resignation	Death or Disability	Termination without Cause	Retirement
Cash payments	Earned but unpaid base salary and paid time-off benefits	Earned but unpaid base salary and paid time-off benefits	Earned but unpaid base salary and paid time-off benefits	Earned but unpaid base salary and paid time-off benefits
Annual Incentive	Forfeit	Prorated award	Forfeit	Prorated award
Equity Awards	Forfeit unvested equity	Accelerated vesting of unvested equity	Forfeit unvested equity	Forfeit unvested equity
LTCIP	Forfeit	Prorated award	Forfeit	Prorated award

The following table sets forth the estimated payments due to executives without employment agreements under various termination scenarios (other than in connection with a change in control, which is addressed separately below). The table assumes the termination date occurred on December 31, 2011.

Name and Compensation Component	Termination for Cause or Resignation	Death or Disability	Termination without Cause	Retirement
Jay B. Neese				
Cash payments	$72,401	$ 72,401	$72,401	n/a (1)
Annual Incentive	$ 0	$ 523,813	$ 0	n/a (1)
Equity Awards	$ 0	$3,103,757	$ 0	n/a (1)
LTCIP	$ 0	$ 137,495	$ 0	n/a (1)
Total	$72,401	$3,627,560	$72,401	n/a (1)
Perry H. Richards				
Cash payments	$42,561	$ 42,561	$42,561	n/a (1)
Annual Incentive	$ 0	$ 234,900	$ 0	n/a (1)
Equity Awards	$ 0	$ 915,902	$ 0	n/a (1)
LTCIP	$ 0	$ 46,665	$ 0	n/a (1)
Total	$42,561	$1,150,802	$42,561	n/a (1)
Eric L. Dady				
Cash payments	$57,804	$ 57,804	$57,804	$ 57,804
Annual Incentive	$ 0	$ 274,050	$ 0	$274,050
Equity Awards	$ 0	$ 468,109	$ 0	$ 0
LTCIP	$ 0	$ 37,504	$ 0	$ 37,504
Total	$57,804	$ 742,159	$57,804	$369,358

(1) Messrs. Neese and Richards are not yet eligible to retire.

Potential Payments upon a Change in Control: Severance Plan

Looking Ahead

In response to feedback from shareholders through our first "Say on Pay" vote and to align with competitive best practices, our Compensation Committee approved revisions to the QEP Executive Severance Plan in February 2012. The changes include the removal of excise tax gross-ups, the introduction of a tiered approach to benefits under the plan, a simpler calculation of the cash payment, and an increase in the health and welfare benefit continuation period consistent with competitive practice.

For 2011, under the double-trigger QEP Executive Severance Plan in effect at that time, participants would have received certain severance benefits upon termination following a change in control if such termination was initiated by the employer within three years following the change in control for any reason other than for cause, death or disability, or by the participant for good reason. The severance benefits would have included a cash severance payment equal to twice the sum of 1) annual base salary; 2) the higher of the average of the annual bonuses they actually received or the target established for them for the three fiscal years prior to the change in control; plus 3) the target bonus under LTCIP for the single performance period beginning in the year of termination. The benefits also include prorated payments under the annual bonus plan(s) and LTCIP, except with respect to the 2009 to 2011 and 2010 to 2012 performance periods under the LTCIP, which were settled in restricted stock at the time of the spin-off. Each participant would also have received a payment representing the difference between the net present value of the benefits under the QEP Pension Plan and the SERP calculated at the time of their termination (retirement benefit), and the retirement benefit with two additional years of credited service. Any other payments and benefits provided under other plans due to a change in control would have been triggered, *i.e.* unvested equity would vest under the terms of LTSIP and participants would receive any deferred compensation to which they are entitled under the terms of the Wrap Plan and the SERP. Additionally, these named executive officers would have been entitled, at no cost to the executives, to medical and dental insurance coverage, basic and supplemental life insurance, accidental death or dismemberment and disability coverage under current employee plans for six months after the date of termination. As of December 31, 2011, the QEP Severance Plan included a gross-up tax provision to make executives whole for the impact of excise taxes under Section 280G of the Code, however, in February 2012, the Board removed the gross-up tax provision from the severance plan, and made certain other changes as discussed above. All severance payments are subject to Section 409A of the Code.

Under the QEP Executive Severance Plan, a Change in Control is deemed to have occurred if: (i) any "person" (within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, is or becomes the beneficial owner (as such term is used in Rule 13d-3 under the Exchange Act) of securities of the Company representing 25% or more of the combined voting power of the Company; or (ii) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, as of June 30, 2010, constitute the Company's Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's shareholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on June 30, 2010, or whose appointment, election or nomination for election was previously so approved or recommended; or (iii) the Company's shareholders approve a merger or consolidation of the Company or any direct or indirect subsidiary of the Company with any corporation, other than a merger or consolidation that would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 60% of the combined voting power of the securities of the Company or such surviving entity or its parent outstanding immediately after such merger or consolidation, or a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or (iv) the Company's shareholders approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 60% of the combined voting power of the voting securities of which are owned by the shareholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale. A Change in Control, however, shall not be considered to have occurred until all conditions precedent to the transaction, including but not limited to, all required regulatory approvals have been obtained.

Under the QEP Executive Severance Plan, "good reason" means any of the following events or conditions which occur without the participant's written consent, and which remain in effect after notice has been provided by the participant to the Company of such material reduction and the expiration of a 30 day cure period: (i) a material diminution in the participant's base compensation; (ii) a material diminution in the participant's authority, duties, or responsibility; (iii) a material diminution in the authority, duties, or responsibilities of the supervisor to whom the participant is required to report, including a requirement that a participant report to a corporate officer or employee instead of reporting directly to the Board; (iv) a material diminution in the budget over which the participant retains authority; (v) a material change in the geographic location at which the participant performs services; or (vi) any other action or inaction that constitutes a material breach by an employer of the participant's employment agreement (if any).

If there had been a termination due to a change in control on December 31, 2011 that triggered the severance benefits, the following are estimates of the value of the amounts and benefits payable under the QEP Executive Severance Plan:

Named Executive Officer	Cash Severance	Annual Incentive	LTCIP Awards	Equity Awards	Health & Retirement Benefits	Gross Up(3)	Total(1)
Mr. Stanley(2)	$6,369,706	$750,000	$316,645	$6,512,707	$630,526	$ 0	$14,579,584
Mr. Doleshek(2)	$3,682,022	$441,000	$154,157	$5,424,331	$479,410	$2,015,704	$12,196,624
Mr. Neese	$2,783,101	$361,250	$137,495	$3,103,748	$ 80,705	$1,318,731	$ 7,785,031
Mr. Richards	$1,334,697	$135,000	$ 46,655	$ 915,903	$ 44,358	$ 0	$ 2,476,624
Mr. Dady	$1,308,000	$189,000	$ 37,504	$ 468,110	$174,617	$ 700,216	$ 2,877,447

(1) These amounts do not include any payments of deferred compensation under the Wrap Plan or payment of any SERP benefits.

(2) Mr. Stanley's and Mr. Doleshek's employment contracts limit their payments to the higher of any amount payable under the QEP Executive Severance Plan or under their employment contracts in the event of a change in control, but not both. Amounts reported in the table above represent amounts payable under the QEP Executive Severance Plan.

(3) Applicable when excise tax has been triggered.

Director Compensation

Non-employee directors receive a combination of cash and stock-based compensation designed to attract and retain qualified candidates to serve on our Board. In setting director compensation, our Board considers the significant amount of time that directors spend in fulfilling their duties to our Company and our shareholders, as well as the skill level required by our Board members. The Compensation Committee is responsible for determining the type and amount of compensation for non-employee directors. The Compensation Committee directly retained the Consultant to assist in the annual review of director compensation by providing benchmark compensation data and recommendations for compensation program design. Employee directors are not separately compensated for their service on the Board.

In February 2011, the Compensation Committee approved the new design of the director compensation program as well as the amounts paid under the program, effective April 2011. The changes brought our directors' total compensation in line with the market median and reflect best practice by simplifying the program. The new program removes per meeting fees and provides a standard annual retainer based on role.

Retainer and Meeting Fees. The table below describes the new director compensation program which was implemented in the second quarter of 2011.

Type of Fee	Amount
Annual Board Member Retainer	$ 70,000
Additional Audit Committee Chair Retainer	$ 15,000
Additional Compensation Committee Chair Retainer	$ 15,000
Additional Other Committee Chair Retainer	$ 10,000
Additional Chairman of the Board Retainer	$150,000
Annual Equity Grant	$175,000

Long-Term Stock Incentive Plan. In 2011, directors received an annual equity grant of restricted stock pursuant to the LTSIP.

Director Deferred Compensation

Non-employee directors are eligible to participate in the Deferred Compensation Wrap Plan, which allows non-employee directors to defer compensation paid to them (both cash compensation and equity compensation). Payments of phantom share balances upon a director's cessation of board service are made in cash. Directors are credited with earnings and dividends on the phantom shares.

Director Compensation Table for 2011

The following table sets forth information concerning total director compensation earned by each non-employee director during 2011:

Name (a)	Fees Earned or Paid in Cash ($)(1) (b)	Stock Awards ($)(1)(2) (c)	Option Awards ($)(3) (d)	Total ($) (h)
Phillips S. Baker, Jr.	72,325	175,000	0	247,325
L. Richard Flury	85,950	175,000	0	260,950
Robert E. McKee III	132,200	175,000	0	307,200
Keith O. Rattie	204,500	175,000	0	379,500
M. W. Scoggins	82,200	175,000	0	257,200
David A. Trice	55,000	114,912	0	169,912
James A. Harmon(4)	34,975	175,000	0	209,975

(1) Some directors deferred amounts as described above.

(2) The dollar amount indicated for each of these restricted stock awards is the aggregate grant date fair value computed in accordance with FASB ASC Topic 718, excluding the effect of estimated forfeitures. The assumptions used in determining the grant date fair value of these awards are described in Note 10 to consolidated financial statements included in Item 8 of Part II of the Company's 2011 Form 10-K. On February 25, 2011, all non-employee directors of QEP received a grant of QEP restricted stock or phantom restricted stock. Directors had the following aggregate stock awards or phantom shares outstanding as of December 31, 2011:

Name	Number of Restricted Shares/Restricted Stock Units	Number of Phantom Shares
Phillips S. Baker, Jr.	0	4,489
L. Richard Flury	4,480	20,783
Robert E. McKee III	0	28,599
Keith O. Rattie	38,735*	0
M. W. Scoggins	0	26,941
David A. Trice	0	2,804
James A. Harmon	0	0

* Mr. Rattie has 4,480 shares of restricted stock and 34,255 restricted stock units

(3) Directors had the following aggregate options outstanding at December 31, 2011:

Name	Number of Vested Option Shares*
Phillips S. Baker, Jr.	0
L. Richard Flury	14,000
Robert E. McKee III	14,000
Keith O. Rattie	882,174
M. W. Scoggins	0
David A. Trice	0
James A. Harmon	14,000

* All non-employee directors options are vested.

(4) Mr. Harmon retired from service as a director in May 2011.

EQUITY COMPENSATION PLAN INFORMATION

As of December 31, 2011, we have a shareholder-approved equity incentive compensation plan under which shares of our common stock are authorized for issuance to directors, officers, employees, and consultants. All outstanding awards relate to our common stock.

	Number of Shares of Common Stock to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares of Common Stock Remaining Available for Future Issuance Under Equity Compensation Plans
Equity Compensation Plans Approved by Shareholders	3,914,514	$19.30	14,096,942
Equity Compensation Plans Not Approved by Shareholders	—	—	—
Total	3,914,514	$19.30	14,096,942

ITEM NO. 2 – APPROVAL, BY NON-BINDING ADVISORY VOTE, OF THE COMPENSATION OF THE COMPANY'S NAMED EXECUTIVE OFFICERS

We are seeking a non-binding advisory vote from shareholders to approve the compensation awarded to our Named Executive Officers. The Company has adopted comprehensive executive compensation programs. The proxy statement discloses material information regarding the compensation of the Company's Named Executive Officers, so that shareholders can evaluate the Company's approach to compensating its executives. The Company and the Compensation Committee of the Board of Directors continually monitor executive compensation programs and adopt changes to reflect the dynamic marketplace in which the Company competes for talent, as well as general economic, regulatory and legislative developments affecting executive compensation and to be responsive to the concerns of our shareholders. We recently amended the QEP Executive Severance Plan for our Named Executive Officers and other officers and key employees of the Company to eliminate tax gross-up payment obligations to those individuals. Please refer to the sections entitled *Compensation Discussion and Analysis* and *Compensation Tables* of this proxy statement for a detailed discussion of the Company's executive compensation practices and philosophy.

You have the opportunity to vote "for", "against" or "abstain" from voting on the following resolution relating to executive compensation:

> RESOLVED, that the shareholders of QEP Resources, Inc. common stock approve the compensation of the Company's executives as disclosed pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis and the Compensation Tables sections and related material disclosed in the proxy statement.

The vote on this resolution is not intended to address any specific element of compensation; rather, the vote relates to the compensation of our named executive officers as disclosed in this proxy statement in accordance with the SEC's compensation disclosure rules. The vote is advisory, which means that it is not binding on the Company, our Board or the Compensation Committee. To the extent there is any significant vote against our named executive officer compensation as disclosed in this proxy statement, our Compensation Committee will evaluate whether any actions are necessary to address the concerns of shareholders.

Vote Needed for Passage of Proposal

This proposal will be approved on an advisory basis if it receives the affirmative vote of a majority of the shares present or represented and entitled to vote either in person or by proxy. As noted earlier in this proxy statement, broker non-votes will not affect the outcome of this proposal, and abstentions will be equivalent to a vote against this proposal.

Board Recommendation

The Board of Directors recommends that shareholders vote for the resolution for the following reasons:

- Our severance protections are aligned with market practices, and we have recently eliminated the use of excise-tax gross-ups for all employees;
- Our program is heavily weighted towards performance-based pay: our annual incentives pay out based on performance against key financial and operational metrics, and the ultimate value delivered by our long-term incentives is tied to both absolute and relative shareholder return performance;
- Our program creates a strong link between our executives' financial interests and shareholders through the use of stock ownership guidelines and a significant focus on long-term incentive compensation with stock price and shareholder return metrics;
- Our compensation amounts are competitive with an appropriate group of exploration and production peer companies, particularly after taking into account our strong operating and financial performance for 2011;
- Our Compensation Committee uses an independent executive compensation advisor who reports directly to the Compensation Committee; and
- Our use of perquisites is minimal and our executive benefits are limited to simply restoring the benefits lost under our qualified retirement plans due to income limitations.

For the above reasons, the Board of Directors recommends that shareholders vote "FOR" this proposal.

ITEM NO. 3 – APPROVAL OF MATERIAL TERMS OF THE CASH INCENTIVE PLAN

At the time of the Company's separation from Questar Corporation, our Board of Directors adopted the AMIP II (annual incentive plan for certain officers) and the LTCIP. These plans were established to provide cash incentive awards that qualified as tax deductible compensation under Section 162(m) of the Code. In order to simplify administration and to continue to provide tax deductible cash incentive awards, we are requesting approval by shareholders of the material terms of the Cash Incentive Plan, which will replace the AMIP II and LTCIP, and was unanimously recommended for adoption by the Board of Directors.

The Cash Incentive Plan allows the Company to make awards that qualify as "performance-based compensation" under Section 162(m) of the Code. Section 162(m) generally limits the Company's federal income tax deduction for compensation paid to certain "covered employees" (generally the named executive officers other than the chief financial officer) to $1 million each, unless all amounts in excess of $1 million qualify for an exception to the limit. One of the available exceptions is for compensation that qualifies as "performance-based". This exception allows amounts awarded under the Cash Incentive Plan to be deductible by the Company for federal income tax purposes, even if, when combined with other compensation, the award causes the compensation of any executive to exceed $1 million.

The material terms of the Cash Incentive Plan being submitted for approval include (i) the employees eligible to receive awards under the Cash Incentive Plan, (ii) a description of the business criteria on which the performance goals are based, and (iii) the maximum amount of compensation that could be paid to any employee if the performance goals are achieved.

A summary of the principal provisions of the Cash Incentive Plan is set forth below. This summary is qualified in its entirety by reference to the Cash Incentive Plan. The entire Plan is provided in Appendix A to this Proxy Statement. The Cash Incentive Plan provides the Company with flexibility to award key employees both short and long-term cash incentives. The Board of Directors believes this flexibility in awarding various types of incentive compensation is important in order to align employee performance with key measures of both short- and long-term performance and to provide a competitive compensation program.

Description of the Cash Incentive Plan

Authority of Committee. The Cash Incentive Plan shall be administered by the Compensation Committee of the Board (the "Committee"). The Committee has the authority, among other things, to determine the eligible participants and to establish performance goals.

Eligibility. Eligibility under the Cash Incentive Plan is limited to the highest paid officers and key employees of the Company who are approved by the Committee to participate in the Cash Incentive Plan.

Form of Payment. Payment of awards under the Cash Incentive Plan will be made in cash.

Performance Period. Each performance period under the Cash Incentive Plan may be as short as one year or as long as three years as determined by the Committee.

Designation of Participants, Performance Period, and Performance Goals. Within 90 days of the beginning of each performance period, but in no event after 25% of the relevant performance period has lapsed, the Committee shall (i) select the participants eligible to receive awards, (ii) designate the applicable performance period, (iii) establish the target award for each participant, and (iv) establish the performance goals and the underlying performance criteria that must be achieved in order for the participant to receive an award for such performance period.

Performance Goals. The performance goals that will be used to determine whether an award is payable will be based on one or any combination of the following criteria, in either absolute or relative terms, for the Company or any business unit, as determined by the Committee: (a) total shareholder return; (b) return on assets, return on equity or return on capital employed; (c) measures of profitability such as earnings per share, corporate or business unit net income, net income before extraordinary or one-time items, earnings before interest and taxes, earnings before interest, taxes, depreciation and amortization, or earnings before interest, depreciation, amortization, taxes and exploration expense; (d) cash flow from operations; (e) gross or net revenues or gross or net margins; (f) levels of operating expense or other expense items reported on the income statement; (g) measures of customer satisfaction and customer service; (h) safety; (i) annual or multi-year average reserve growth, production growth or production replacement, either absolute or on an appropriate per unit basis (e.g. reserve or production growth per diluted share; (j) efficiency or productivity measures such as annual or multi-year average finding costs, absolute or per unit operating and maintenance costs, lease operating expenses, inside-lease operating expenses, operating and maintenance expense per decatherm or customer or fuel gas reimbursement percentage; (k) satisfactory completion of a major project or organizational initiative with specific criteria set in advance by the Committee defining "satisfactory"; (l) debt ratios or other measures of credit quality or liquidity; (m) production and production growth; and (n) strategic asset sales or acquisitions in compliance with specific criteria set in advance by the Committee.

Committee Certification and Payment of Awards. At the end of each performance period, the Committee shall determine whether the performance goals established for such performance period have been satisfied. Prior to approval of any awards the Committee must certify in writing that the performance goals have been satisfied. The Committee shall then determine the amount of the award to be paid to each participant for the performance period under the terms of the Cash Incentive Plan.

Termination of Employment. If a participant's employment terminates for any reason other than death, disability, retirement, or a change in control, the participant generally will not be entitled to any payment under the Cash Incentive Plan. If a participant's employment terminates by reason of death, disability, or retirement, a prorated portion of the award shall be paid at the end of the performance period based on the final performance calculation. If a participant's employment terminates as a result of a change in control, the participant shall be entitled to a payment as determined by the Compensation Committee calculated in a manner consistent with Section 162(m) within 30 days of the date of separation from service, unless the participant is also a participant in the Executive Severance Plan, in which case the participant will receive a payment pursuant to that plan and not pursuant to the Cash Incentive Plan.

Maximum Payouts. The maximum payments that can be made under the Cash Incentive Plan in any fiscal year to any participant are (i) $4,000,000 for all annual cash incentive awards payable in such year and (ii) $10,000,000 for all long-term cash incentive awards payable in such year.

Amendment and Termination of the Plan. The Board may at any time amend, modify, or terminate the Cash Incentive Plan, but such action shall not affect awards outstanding under the Cash Incentive Plan. No amendment to change the maximum award payable or the possible performance goals shall be effective without shareholder approval.

Award Information. No cash payouts will be made under the Cash Incentive Plan if the material terms of the Plan are not approved by shareholders. The Company intends that, upon shareholder approval of the material terms of the Cash Incentive Plan as set forth in this Proposal, awards under the Cash Incentive Plan will qualify as performance-based compensation that is exempt from the annual deduction limit provided under Code Section 162(m). Because of ambiguities and uncertainties as to the application and interpretation of Section 162(m) and the regulations issued thereunder, no assurance can be given, notwithstanding the Company's efforts, that compensation intended by the Company to satisfy the requirements for deductibility under Section 162(m) will in fact do so.

New Plan Benefits

On February 13, 2012, the Compensation Committee awarded performance share units as long-term cash incentive awards under the Cash Incentive Plan, subject to approval of the Cash Incentive Plan by the Company's shareholders at the Annual Meeting. The awards have a three-year performance period ending December 31, 2014, and a portion or a multiple of the performance share units can be earned depending on our total shareholder return relative to a group of peer companies during the performance period. If the Cash Incentive Plan is not approved by shareholders prior to the end of the performance period, no payment shall be made under this Plan.

The table below sets forth the target amounts granted under the Cash Incentive Plan by our Compensation Committee in February 2012 to each of our named executive officers, to our executive officers as a group, to our non-executive director group and to our employee group, which consists of all officers who are not executive officers.

NEW PLAN BENEFITS
QEP RESOURCES, INC. CASH INCENTIVE PLAN

Name and Position	Dollar Value (Annual Incentive) (1) ($)	Number of Units (Long-term Cash Incentive) (2) (#)
Named Executive Officers		
Charles B. Stanley	$ 790,000	44,769
Richard J. Doleshek	$ 463,500	21,575
Jay B. Neese	$ 379,100	19,418
Perry H. Richards	$ 145,000	6,473
Eric L. Dady	$ 204,000	7,012
Executive Group (3)	$2,238,100	109,226
Non-Employee Director Group	$ 0	0
Employee Group (4)	$1,232,850	26,701

(1) The actual payment may be 0-200% of the listed target amount.
(2) These long-term incentive awards are stock-denominated, but will be paid in cash. The listed amount is the target.
(3) This group includes the named executive officers and other executive officers.
(4) This group includes non-executive officers.

Federal Income Tax Consequences

The following is a brief description of the principal federal income tax consequences relating to awards made under the Cash Incentive Plan. This summary is based on our understanding of present federal income tax law and regulations. The summary does not purport to be complete or applicable to every specific situation.

Participants will recognize ordinary income equal to the amount of the cash received with respect to an award in the year of receipt. That income will be subject to applicable income and employment tax withholding. If and to the extent that payments made under the Cash Incentive Plan satisfy the requirements of Section 162(m) of the Code and otherwise satisfy the requirements of deductibility under federal income tax law, we will receive a corresponding deduction for the amount constituting ordinary income to the participant.

Vote Needed for Passage of Proposal

To be approved under Delaware law, this proposal must receive the affirmative vote of a majority of the shares of common stock present in person or by proxy and entitled to vote. For purposes of satisfying the shareholder approval requirement under Section 162(m) of the Code only, the proposal is approved if a majority of the votes cast on the proposal are in favor of the proposal.

Board Recommendation

The Board of Directors recommends a vote "FOR" the approval of the material terms of the Cash Incentive Plan.

ITEM NO. 4 – RATIFICATION OF OUR INDEPENDENT AUDITOR

On November 11, 2011, the Audit Committee approved the engagement of PricewaterhouseCoopers LLP ("PwC") as the Company's independent registered public accounting firm for the year ending December 31, 2012. In connection with the selection of PwC, also on November 11, 2011, the Audit Committee informed Ernst & Young LLP ("Ernst & Young") that it would be dismissed as the Company's independent registered public accounting firm no later than the date of the filing of the Company's Form 10-K for the 2011 fiscal year. Ernst & Young was formally dismissed on February 24, 2012. The Audit Committee selected PwC as the Company's new independent auditor following a request for proposals and an extensive selection process. We are asking shareholders to ratify the selection of PwC. Although ratification is not required by our Bylaws or otherwise, the Board is submitting the selection of PwC for ratification because we value shareholder views on the Company's independent registered public accounting firm. In the event that shareholders fail to ratify the selection, our Audit Committee will consider the selection of a different firm. Even if the selection is ratified, the Audit Committee, in its discretion, may select a different independent registered public accounting firm at any time during the year if the Committee determines that such a change would be in the best interests of our Company and shareholders.

During the years ended December 31, 2010 and 2009, and through the date PwC was engaged by the Company, neither the Company nor anyone on its behalf has consulted with PwC with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's consolidated financial statements, and neither written nor oral advice was provided to the Company that PwC concluded was an important factor considered by the Company in reaching a decision as to any accounting, auditing or financial reporting issue; or (ii) any matter that was either the subject of disagreement (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) or a reportable event (as defined by Item 304(a)(1)(v) of Regulation S-K).

The report of Ernst &Young on the Company's consolidated financial statements for the years ended December 31, 2010 and 2009 did not contain an adverse opinion or disclaimer of an opinion, and was not qualified or modified as to uncertainty, audit scope or accounting principles, except that the report included an explanatory paragraph related to the Company's adoption of ASC 810-10-65-1, "Noncontrolling Interests in Consolidated Financial Statements", and SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting."

During the years ended December 31, 2010 and 2009, and through February 24, 2012, there were no disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) with Ernst & Young on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Ernst & Young, would have caused Ernst & Young to make reference to the subject matter of the disagreement in its report on the consolidated financial statements for such year. During the years ended December 31, 2010 and 2009, and through February 24, 2012, there were no reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

Representatives of PwC and Ernst & Young will be present at the Annual Meeting to answer appropriate questions. They also will have the opportunity to make a statement if they desire to do so.

Audit Fees

Ernst & Young, the Company's former independent public accounting firm, billed the Company for services from July 1, 2010 until December 31, 2011, as follows. The fees listed are aggregate fees for services performed for each year regardless of when the fee was actually billed.

	2010(1)	2011
Audit Fees(2):	$602,038	$685,400
Audit-related Fees:	0	0
Tax Fees:	0	0
All Other Fees:	0	0
Total	$602,038	$685,400

(1) These are the audit fees QEP paid in the six months after completion of the spin-off.

(2) Audit fees, including expenses, relate to Ernst & Young's fiscal-year audit and interim reviews of the annual financial statements of the Company and its reporting subsidiaries. This category also includes fees for audits provided in connection with statutory filings, including consents and review of documents filed with the SEC. Audit fees also include charges related to compliance with the Sarbanes-Oxley Act of 2002.

Pre-Approval Policy

The Audit Committee has adopted procedures for pre-approving all audit and non-audit services provided by its independent accounting firm. These procedures include reviewing fee estimates for audit services and permitted recurring non-audit services, and authorizing the Company to execute letter agreements setting forth such fees. Audit Committee approval is required for any services to be performed by the independent accounting firm that are not specified in the letter agreements. We have delegated approval authority to the Chairman of the Audit Committee, but any exercises of such authority are reported to the Audit Committee at the next meeting. All fees paid to Ernst & Young for years ended December 31, 2010 and 2009 were pre-approved by the Audit Committee in accordance with this policy.

Vote Needed for Passage of Proposal

Ratification of the selection of PricewaterhouseCoopers LLP as the Company's independent auditor for fiscal year 2012, requires the affirmative vote of a majority of the shares of our common stock present in person or by proxy at the Annual Meeting and entitled to vote on the matter. If this selection is not ratified by shareholders, the Audit Committee may reconsider its decision. As noted earlier in this proxy statement, for purposes of determining whether this proposal has received a majority vote, abstentions will be included in the vote totals; therefore, an abstention has the same effect as a negative vote. Broker non-votes will not be included in the vote totals and, therefore, will have no effect on the vote.

Board Recommendation

The Board of Directors recommends that you vote "FOR" the ratification of the selection of PwC as our independent auditor.

ITEM NO. 5 – SHAREHOLDER PROPOSAL REGARDING BOARD DECLASSIFICATION

The Illinois State Board of Investment, 180 North LaSalle Street, Suite 2015, Chicago IL, 60601, owner of 14,699 shares of QEP Resources stock advised the Company that a representative will present the following resolution at the Annual Meeting for action by the shareholders. Mr. Gerald Armstrong, another shareholder of the Company, also submitted a resolution to declassify the board but agreed to withdraw it in light of the proposal set forth below, which the Company received on an earlier date.

> RESOLVED, that shareholders of QEP Resources, Inc. urge the Board of Directors to take all necessary steps (other than any steps that must be taken by shareholders) to eliminate the classification of the Board of Directors and to require that all directors elected at or after the annual meeting held in 2013 be elected on an annual basis. Implementation of this proposal should not prevent any director elected prior to the annual meeting held in 2013 from completing the term for which such director was elected.

Supporting Statement of Shareholder

This resolution was submitted by the Illinois State Board of Investment. The Harvard Law School Shareholder Rights Project represented and advised the Illinois State Board of Investment in connection with this resolution.

The resolution urges the board of directors to facilitate a declassification of the board. Such a change would enable shareholders to register their views on the performance of all directors at each annual meeting. Having directors stand for elections annually makes directors more accountable to shareholders, and could thereby contribute to improving performance and increasing firm value.

Over the past decade, many S&P 500 companies have declassified their board of directors. According to data from FactSet Research Systems, the number of S&P 500 companies with classified boards declined by more than 50%; and the average percentage of votes cast in favor of shareholder proposals to declassify the boards of S&P 500 companies during the period January 1, 2010 – June 30, 2011 exceeded 75%.

The significant shareholder support for proposals to declassify boards is consistent with empirical studies reporting that classified boards could be associated with lower firm valuation and/or worse corporate decision-making. Studies report that:

- Classified boards are associated with lower firm valuation (Bebchuk and Cohen, 2005; confirmed by Faleye (2007) and Frakes (2007));
- Takeover targets with classified boards are associated with lower gains to shareholders (Bebchuk, Coates, and Subramanian, 2002);
- Firms with classified boards are more likely to be associated with value-decreasing acquisition decisions (Masulis, Wang, and Xie, 2007); and
- Classified boards are associated with lower sensitivity of compensation to performance and lower sensitivity of CEO turnover to firm performance (Faleye, 2007).

Please vote for this proposal to make directors more accountable to shareholders.

Statement of Board of Directors

Our Company's Board of Directors has considered the shareholder proposal relating to declassification of the Board, and has decided not to oppose the proposal and to make no voting recommendation to shareholders. The proposal, which is advisory in nature, would constitute a recommendation to the Board if approved by shareholders. The Board recognizes that board classification is a controversial topic and believes that there are valid arguments in favor of, and in opposition to, classified boards. The Board wants to use this proposal to provide an opportunity for shareholders to express their views on this subject without being influenced by any recommendation the Board might make.

Supporters of classified boards contend, among other things, that a classified board can promote stability and continuity of leadership and enhance a board's ability to respond to takeover bids by making it more difficult for an unsolicited bidder to gain control of a company. Opponents of classified boards often make arguments such as those set forth in the proponent's supporting statement.

Vote Needed for Passage of Proposal

This proposal will be approved if it receives the affirmative vote of the majority of the shares of our common stock present in person or by proxy at the Annual Meeting entitled to vote on the matter. If shareholders return a validly executed proxy solicited by the Board of Directors, the shares represented by the proxy will be voted on this proposal in the manner specified by the shareholder. As noted earlier, abstentions will be included in the vote totals, and, therefore, an abstention has the same effect as a negative vote. If shareholders do not specify the manner in which their shares represented by a validly executed proxy solicited by the Board are to be voted on this proposal, such shares will not be voted, will not be included in the vote totals and accordingly will not have any effect on whether or not the proposal is approved.

Shareholder approval of this proposal would not, by itself, eliminate the classified board. In order to eliminate the classified board, QEP's Charter requires a supermajority vote of 80% of the issued and outstanding capital stock.

Board Recommendation

The Board of Directors makes no recommendation on this proposal.

OTHER MATTERS

Annual Report and 2011 Form 10-K

Upon request, we will promptly send a copy of the Annual Report, 2011 Form 10-K (excluding exhibits) and proxy statement to you. Contact Abigail L. Jones at 1050 17th Street, Denver, Colorado 80265 (303)640-4277 to make the request.

Shareholder Nominations and Proposals

To be considered for presentation at our 2013 Annual Meeting of Shareholders and included in the proxy statement pursuant to Rule 14a-8 of the Exchange Act, as amended, a shareholder proposal must be received at the Company's office no later than December 4, 2012.

Pursuant to the Company's Bylaws, business must be properly brought before an annual meeting in order to be considered by shareholders. The Bylaws specify the procedure for shareholders to follow in order to bring business before an annual meeting. A shareholder who wants to nominate a person for election as a director or who wants to submit a proposal at the annual meeting without having it considered through the Company's proxy materials must deliver a written notice and additional information specified in our Bylaws by certified mail, to our corporate secretary. Such notice must be received at least 90 days and not more than 120 days prior to the anniversary date of the prior year's annual meeting. Accordingly, with respect to the 2013 Annual Meeting, such notice must be received no earlier than January 15, 2013, and no later than February 14, 2013.

Any proposal (other than a proposal made pursuant to Rule 14a-8) that is received after the time specified above for proposed items of business will be considered untimely under Rule 14a-4(c). The persons named in the proxy will have discretionary authority to vote all proxies with respect to any untimely proposals. A copy of our Bylaws specifying the requirements will be furnished to any shareholder without charge upon written request to our corporate secretary.

Forward-Looking Statements

This proxy statement may include "forward-looking statements" (as defined in the Private Securities Litigation Reform Act of 1995). The forward-looking statements include statements regarding compliance with Section 162(m) and Section 409A of the Code. These statements are based on our current expectations and involve risks and uncertainties that may cause actual results to differ materially from those set forth in the statements, including changes in governmental regulations and interpretations thereunder and other risks identified in the Risk Factors section of our 2011 Form 10-K. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future events or otherwise. Forward-looking statements should be evaluated together with the many uncertainties that affect our business, particularly those mentioned in the Risk Factors section in our 2011 Form 10-K, and in our quarterly reports on Form 10-Q and current reports on Form 8-K.

Delivery of Proxy Statement

The SEC has adopted rules that permit companies and intermediaries (such as brokers) to satisfy the delivery requirements for proxy statements with respect to two or more security holders sharing the same address by delivering a single proxy statement addressed to those security holders. This process, which is commonly referred to as "householding," potentially means extra convenience for security holders and cost savings for companies. This year, a number of brokers with accountholders who are QEP shareholders will be householding our proxy materials. A single proxy statement will be delivered to multiple shareholders sharing an address unless contrary instructions have been received from the affected shareholder. Once you have received notice from your broker that they will be householding communications to your address, householding will continue until you are notified otherwise or until you revoke your consent. If you would prefer to receive a separate copy of the proxy materials or if you are receiving multiple copies and would like to receive a single copy, please notify your broker or direct your request to us as follows: Abigail L. Jones, 1050 17th Street, Denver, Colorado 80265, (303) 640-4277. We will promptly deliver a separate copy to you upon request.

By Order of the Board of Directors

Abigail L. Jones
Corporate Secretary

Appendix A

QEP RESOURCES, INC.
CASH INCENTIVE PLAN

Section 1. Purpose.

The QEP Resources, Inc. Cash Incentive Plan, as it may be amended from time to time (the "Plan"), is designed to provide incentives to the highest paid officers and key employees of QEP Resources, Inc. (the "Company") and its Affiliates (as defined below) to focus their best efforts to pursue and attain major organizational goals. The intent of the Plan is to place a significant portion of the eligible employee's annual and, for certain executives, longer-term compensation at risk by tying it to specific measurable goals that drive long-term shareholder value. Effective January 1, 2012 (the "Effective Date"), the Plan is adopted. The Plan is intended to replace prospectively the QEP Resources, Inc. Annual Management Incentive Plan, Annual Management Incentive Plan II and Long-Term Cash Incentive Plan. Awards made under the QEP Resources, Inc. Long-Term Cash Incentive Plan in years prior to 2012 shall continue to be effective.

Section 2. Definitions.

"Affiliate" means any entity that is treated as the same employer as the Company under Sections 414(b), (c), (m), or (o) of the Code, any entity required to be aggregated with the Company pursuant to regulations adopted under Code section 409A, or any entity otherwise designated as an Affiliate by the Company.

"Board" means the Board of Directors of the Company or a successor to the Company.

"Code" shall mean the Internal Revenue Code of 1986, as amended.

"Committee" means the Compensation Committee of the Board which is comprised wholly of independent, outside directors and which must include at least two such directors, or such other person or entity to which any responsibilities may be delegated by such Committee.

"Covered Employee" means a Selected Employee who is a "covered employee" as defined in Code section 162(m)(3) and the regulations promulgated pursuant to it or who the Committee believes will be such a Covered Employee for any given Performance Period.

"Designated Beneficiary" means the beneficiary designated by the Selected Employee, in a manner determined by the Committee, to receive amounts due the Selected Employee. In the absence of an effective designation by the Selected Employee, Designated Beneficiary shall mean the Selected Employee's beneficiary(ies) designated by the Selected Employee (or deemed by law to be designated) under the QEP Resources, Inc. Employee Investment Plan, as amended from time to time, or if no such designation exists, the Selected Employee's estate.

"Disability" means a condition that renders a Selected Employee unable to engage in any substantial, gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve months. The foregoing definition of Disability shall be interpreted in a manner consistent with Code section 409A and relevant guidance issued thereunder.

"Employer" means the Company and any of its Affiliates that agree to bear the costs of having its Selected Employees participate in the Plan. The term shall also mean any successor to the Company.

"Fiscal Year" means the calendar year.

"Performance Goals" means the specific, measurable goals set by the Committee in writing for any given Selected Employee and applicable Performance Period. Performance Goals may include multiple goals and may be based on one or more operational or financial criteria. Such goals shall be set by the Committee by such date as is required under Code section 162(m). In setting the Performance Goals for a Performance Period, the Committee may include one or any combination of the following criteria in either absolute or relative terms, for the Company or any business unit within it: (a) total shareholder return; (b) return on assets, return on equity or return on capital employed; (c) measures of profitability such as earnings per share, corporate or business unit net income, net income before extraordinary or one-time items, earnings before interest and taxes, earnings before interest, taxes, depreciation and amortization, or earnings before interest, depreciation, amortization, taxes and exploration expense; (d) cash flow from operations; (e) gross or net revenues or gross or net margins; (f) levels of operating expense or other expense items reported on the income statement; (g) measures of customer satisfaction and customer service; (h) safety; (i) annual or multi-year average reserve growth, production growth or production replacement, either absolute or on an appropriate per unit basis (e.g. reserve or production growth per diluted share; (j) efficiency or productivity measures such as annual or multi-year average finding costs, absolute or per unit operating and maintenance costs, lease operating expenses, inside-lease operating expenses, operating and maintenance expense per decatherm or customer or fuel gas reimbursement percentage; (k) satisfactory completion of a major project or organizational initiative with specific criteria set in advance by the Committee defining "satisfactory"; (l) debt ratios or other measures of credit quality or liquidity; (m) production and production growth; and (n) strategic asset sales or acquisitions in compliance with specific criteria set in advance by the Committee.

"Performance Period" means one or more periods of time, which may be of varying and overlapping durations, as the Committee may select, over which the attainment of one or more Performance Goals will be measured for the purpose of determining a Selected Employee's or Covered Employee's entitlement to a payout under this Plan. A Performance Period can be as short as one year and as long as three years.

"Retirement" means a voluntary Separation from Service on or after attainment of age 55 with 10 years of Service.

"Selected Employee" means any of the highest paid officers and key employees of an Employer who are selected to participate in the Plan for a Performance Period in accordance with Section 4 below.

"Separation from Service" means a Selected Employee's termination or deemed termination from employment with the Employer. For purposes of determining whether a Separation from Service has occurred, the employment relationship is treated as continuing intact while the Selected Employee is on military leave, sick leave or other bona fide leave of absence if the period of such leave does not exceed six months, or if longer, so long as the Selected Employee retains a right to reemployment with his Employer under an applicable statute or by contract. For this purpose, a leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Selected Employee will return to perform services for the Employer. If the period of leave exceeds six months and the Selected Employee does not retain a right to reemployment under an applicable statute or by contract, the employment relationship will be deemed to terminate on the first date immediately following such six-month period. For purposes of this Plan, a Separation from Service occurs at the date as of which the facts and circumstances indicate either that, after such date: (i) the Selected Employee and Employer reasonably anticipate the Selected Employee will perform no further services for the Company or an Affiliate (whether as an employee or an independent contractor), or (ii) that the level of bona fide services the Selected Employee will perform for the Company or any Affiliate (whether as an employee or independent contractor) will permanently decrease to no more than 20 percent of the average level of bona fide services performed over the immediately preceding 36-month period or, if the Selected Employee has been providing services to the Company or an Affiliate for less than 36 months, the full period over which the Selected Employee has rendered services, whether as an employee or independent contractor. The determination of whether a Separation from Service has occurred shall be governed by the provisions of Treasury Regulation section 1.409A-1, as amended, taking into account the objective facts and circumstances with respect to the level of bona fide services performed by the Selected Employee after a certain date.

"Service" means a Selected Employee's service as an employee of an Employer.

Section 3. Administration.

The Plan shall be administered by the Committee or its designee; provided, however that the Committee shall not delegate to others any duty or activity required to be performed by the Committee to satisfy requirements of Code section 162(m) or any other statute or regulation. The Committee shall have sole and complete authority to adopt, alter, and repeal administrative rules, guidelines and practices for the operation of the Plan and to interpret the terms and provisions of the Plan. The Committee also shall have sole and complete authority to determine the extent to which Performance Goals have been achieved. The Committee's decisions shall be final and binding upon all parties, including the Employers, shareholders, Selected Employees and Designated Beneficiaries.

Section 4. Eligibility.

Within 90 days of the beginning of a Performance Period, but in no event after 25 percent of the Performance Period has lapsed, the Committee shall designate in writing those highest paid officers and key employees of an Employer who shall be Selected Employees under the Plan for such Performance Period. Only such Selected Employees are eligible to receive awards under this Plan. Notwithstanding the foregoing, the Committee may designate additional officers and key employees of an Employer as Selected Employees and/or change the method of determining the Selected Employee's payout at any time after the commencement of a Performance Period; provided, that, if doing so would disqualify a payment as "qualified performance-based compensation" under Code section 162(m) with respect to a Covered Employee, such action will be taken only if the Committee determines that it would be appropriate to do so.

Section 5. Determination of Performance Goals.

Within 90 days after the beginning of a Performance Period, but in no event after 25 percent of the Performance Period has lapsed, the Committee or its designee shall establish in writing for each Selected Employee (i) the Performance Goals and the underlying performance criteria applicable to the Performance Period, and (ii) a bonus payable upon the achievement of the Performance Goals. Performance Goals for Covered Employees must be objective and must satisfy the third-party objectivity standards under Code section 162(m) and regulations adopted pursuant to it. In addition, when provided for by the Committee at the time the Performance Goals are established, the Performance Goals may be adjusted to exclude the effect of any of one or more of the following events that occur during the Performance Period: (i) asset write-downs; (ii) litigation, claims, judgments or settlements; (iii) the effect of changes in tax law, accounting principles or other such laws or provisions affecting reported results; (iv) accruals for reorganization and restructuring programs; (v) material changes to invested capital from pension and post-retirement benefits-related items and similar non-operational items; and (vi) any extraordinary, unusual, non-recurring or non-comparable items: (A) as described in Accounting Principles Board Opinion No. 30, (B) as described in management's discussion and analysis of financial condition and results of operations appearing in the Company's Annual Report to shareholders for the applicable year, or (C) as publicly announced by the Company in a press release or conference call relating to the Company's results of operations or financial condition for a completed quarterly or annual fiscal period.

As soon as reasonably practicable after the close of a Performance Period, the Committee shall determine cash payments to be made under the terms of this Plan. Any payments made under this Plan shall be contingent upon achieving the Performance Goals set in advance for the Performance Period in question. The Committee shall certify in writing prior to approval of any awards that such Performance Goals have been satisfied. Approved minutes of the Committee may be used for this purpose.

The maximum payment that may be made in any Fiscal Year to any Selected Employee under this Plan with respect to a one-year Performance Period is $4,000,000. The maximum payment that may be made in any Fiscal Year to any Selected Employee under the Plan with respect to a two or three-year Performance Period is $10,000,000.

The cash payments under this Plan, in aggregate, do not have to equal 100 percent of the maximum payout, but cannot exceed such amount. The Committee, in its sole discretion, may reduce the cash award otherwise payable to any employee if it believes that such reduction is in the best interest of the Company and its shareholders, but any reduction cannot result in an increase to one or more Covered Employees. The Committee has no discretion to increase the cash award otherwise payable to any Covered Employee.

All payments shall be made in cash and in a single lump sum no later than the 15th day of the 3rd month following the end of the calendar year that includes the last day of the relevant Performance Period. To be eligible to receive an award, the Selected Employee must be actively employed by an Employer as of the date of payment except as provided below in Section 6.

Section 6. Termination of Employment.

In the event a Selected Employee incurs a Separation from Service prior to the payment of an award for any Performance Period for any reason other than death, Disability, Retirement, or a Change in Control, he shall not be entitled to any payment for such Performance Period under the Plan, unless otherwise determined in writing by the Committee. If a Selected Employee incurs a Separation from Service prior to payment of an award for any Performance Period as a result of death, Disability, or Retirement, his award for the Performance Period (if any), as calculated pursuant to Section 5, shall be prorated based on the length of his service during the Performance Period when compared to the entire period. All prorated awards shall be paid to the Selected Employee (or his Designated Beneficiary in the event of his death) at the time specified in Section 5.

In the event a Selected Employee incurs a Separation from Service as a result of a Change in Control that occurs prior to the payment of an award for any Performance Period, he shall be entitled to receive a payment as determined by the Committee calculated in a manner consistent with Code Section 162(m) for such Performance Period. Such payment shall be made to him within 30 days after his Separation from Service. Notwithstanding the foregoing, in no event shall a Selected Employee who is a participant in the QEP Resources, Inc. Executive Severance Compensation Plan, as amended from time to time, as of the date on which a Change in Control occurs be entitled to such payment.

A Change in Control of the Company shall be deemed to have occurred if (i) any individual, entity, or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934 (the "Exchange Act")) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, is or becomes the beneficial owner (as such term is used in Rule 13d-3 under the Exchange Act) of securities of the Company representing 30 percent or more of the combined voting power of the Company; or (ii) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, as of the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's shareholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date, or whose appointment, election or nomination for election was previously so approved or recommended; or (iii) the consummation of a merger or consolidation of the Company or any direct or indirect subsidiary of the Company with any corporation, other than a merger or consolidation that would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 60 percent of the combined voting power of the securities of the Company or such surviving entity or its parent outstanding immediately after such merger or consolidation, or a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of the Company representing 30 percent or more of the combined voting power of the Company's then outstanding securities; or (iv) the Company's shareholders approve a plan of complete liquidation or dissolution of the Company or there is consummated the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 60 percent of the combined voting power of the voting securities of which are owned by the shareholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale. In addition, if a Change in

Control constitutes a payment event with respect to any payment under the Plan which provides for the deferral of compensation and is subject to Code section 409A, the transaction or event described in clauses (i), (ii), (iii) and (iv) with respect to such payment must also constitute a "change in control event," as defined in Treasury Regulation section 1.409A-3(i)(5) before any such payment can be made.

Section 7. Other Provisions.

(a) Taxes and Withholding. All cash payments made under the Plan are subject to withholding for Federal, state, and other applicable taxes. The Company shall deduct any taxes required by law to be withheld from all amounts paid to a Selected Employee under this Plan.

(b) Source of Funds. All cash payments made under the Plan will be paid from an Employer's general assets and nothing contained in the Plan will require an Employer to set aside or hold in trust any funds for the benefit of any Selected Employee or his Designated Beneficiary.

(c) No Assignment. No right or interest of any Selected Employee under this Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not by way of limitation, execution, levy, garnishment, attachment, pledge, bankruptcy, or in any other manner, and no right or interest of any Selected Employee under the Plan shall be liable for, or subject to, any obligation or liability of such Selected Employee. Any assignment, pledge, encumbrance, charge, transfer, or other act in violation of this provision shall be void.

(d) Amendment and Termination of Plan. The Board may at any time amend, modify, suspend, or terminate the Plan, but such action shall not affect the awards earned and the payment of such awards during any given Performance Period. No amendment to change the maximum award payable to a Selected Employee or the definition of Performance Goals shall be effective without shareholder approval. The Board cannot amend, modify, suspend, or terminate the Plan in any year in which a Change in Control has occurred without the written consent of the affected Selected Employees.

(e) Successor. The Company shall require any successor or assignee, whether direct, indirect, by purchase, merger, consolidation or otherwise, to all or substantially all of the business and/or assets of the Company to assume the obligations under this Plan in the same manner and to the same extent that the Company would be required to perform if no such succession assignment had taken place.

(f) Choice of Law. This Plan will be governed by and construed in accordance with applicable Federal law and, to the extent not preempted by Federal law, in accordance with the laws of the state of Colorado.

(g) 409A Compliance. The payments and benefits provided hereunder are intended to be exempt from or compliant with the requirements of Code section 409A. Notwithstanding any provision of this Plan to the contrary, including, without limitation, Section 7(e) hereof, in the event that the Company reasonably determines that any payments or benefits hereunder are either not exempt from or compliant with the requirements of Code section 409A, the Company shall have the right to adopt such amendments to this Plan or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect), or take any other actions, that are necessary or appropriate (i) to preserve the intended tax treatment of the payments and benefits provided hereunder, to preserve the economic benefits with respect to such payments and benefits, and/or (ii) to exempt such payments and benefits from Code section 409A or to comply with the requirements of Code section 409A and thereby avoid the application of penalty taxes thereunder; provided, however, that this Section 7(h) does not, and shall not be construed so as to, create any obligation on the part of the Company to adopt any such amendments, policies or procedures or to take any other such actions or to indemnify any Covered Employee for any failure to do so.

Notwithstanding anything to the contrary in this Plan, no compensation or benefits shall be paid to a Selected Employee during the 6-month period following his or her Separation from Service from the Company to the extent that the Company determines that the Selected Employee is a "specified employee" at the time of such Separation from Service and that paying such amounts at the time or times indicated in this Plan would be a prohibited distribution under Code section 409A(a)(2)(B)(i) . If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of such 6-month period (or such earlier date upon which such amount can be paid under Code section 409A without being subject to such additional taxes, including as a result of the Selected Employee's death), the Company shall pay to the Selected Employee a lump-sum amount equal to the cumulative amount that would have otherwise been payable to the Selected Employee during such 6-month period.

I hereby certify that this QEP Resources, Inc. Management Compensation Plan was duly adopted by the Board of Directors of QEP Resources, Inc. on , 2012.

Executed on this day of , 2012.

By: ____________________________________

QEP Resources, Inc.

QEP Resources, Inc.

2011 Annual Report

QEP Resources Corporate Profile

QEP Resources, Inc. (NYSE:QEP) is a leading independent natural gas and oil exploration and production company. Our operations are focused in the Rocky Mountain and Midcontinent areas of the United States. We also gather, compress, treat and process natural gas.

With year-end 2011 proved reserves of 3.6 Tcfe, our portfolio of low cost, high quality resource plays provides a solid foundation for sustainable growth. Our 4th quarter 2011 daily net production was over 800 MMcfe comprised of approximately 18% crude oil and natural gas liquids.

QEP Resources is headquartered in Denver, Colorado.

Abbreviations and Definitions

Bbl: Barrel

Bcf: Billion cubic feet of gas

Bcfe: Billion cubic feet of natural gas equivalent

EBITDA: Also referred to as Adjusted EBITDA. Adjusted EBITDA is net income before: discontinued operations, unrealized gain and losses on basis-only swaps, gains and losses from asset sales, interest and other income, income taxes, interest expense, separation costs, loss on early extinguishment of debt, depreciation, depletion and amortization, abandonment and impairment, and exploration expense.

MBbl: Thousand barrels

MMBbl: Million barrels

MMBtu: Million British thermal units

Mcf: Thousand cubic feet of gas

Mcfe: Thousand cubic feet of natural gas equivalents

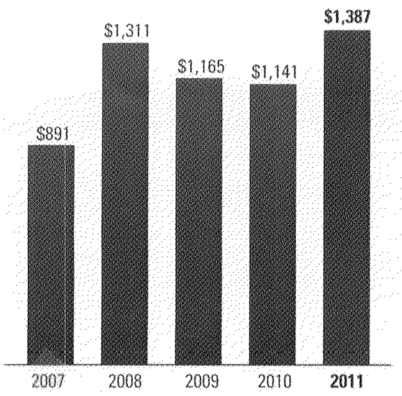
MMcf: Million cubic feet of natural gas

MMcfe: Million cubic feet of natural gas equivalents

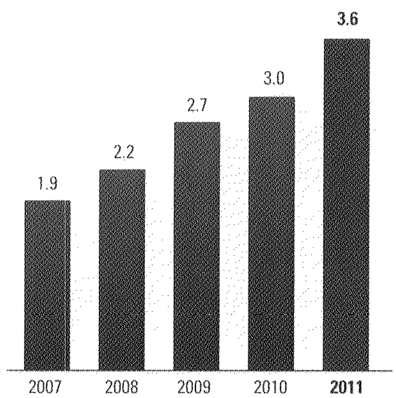
Tcfe: Trillion cubic feet of natural gas equivalents

Recast Results

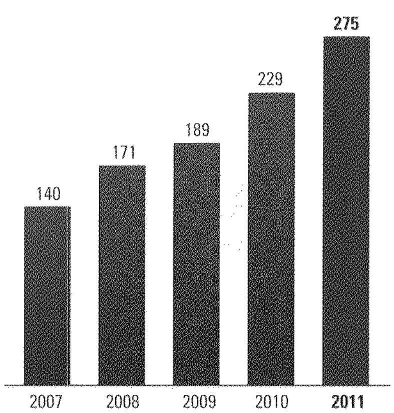
All historical financial and operating results have been recast to reflect the spin-off from Questar Corporation and the distribution of Wexpro Company to Questar Corporation. Wexpro's historical results have been reflected in this Annual Report as discontinued operations.



Adjusted EBITDA
($ in millions)



Proved Reserves
(Tcfe)



Production
(Bcfe)

2011 Highlights

- QEP Energy increased production in 2011 to a record 275 Bcfe, 20% higher than 2010 levels.
- QEP Energy grew proved reserves to 3.6 trillion cubic feet of natural gas equivalent at year-end 2011, a 19% increase over the prior year proved reserve volumes and replaced 312% of 2011 production.
- Crude oil and NGL comprised 24% of year-end 2011 proved reserves, an increase of 107% over year-end 2010 when liquids comprised 14% of total proved reserves.
- QEP Energy increased crude oil and NGL production to 6.5 million barrels in 2011, a 54% increase over the 4.2 million barrels produced in 2010.
- QEP Field Services commenced operations at two natural gas processing plants to extract high-value NGL products. The Iron Horse processing plant started-up in January 2011 and added capacity of 150 MMcf per day. The Blacks Fork II processing plant started-up in July 2011, ahead of schedule, and added capacity of 420 MMcf per day. Field Services total natural gas processing capacity is now 1.37 Bcf per day.
- Adjusted EBITDA for the full-year 2011 was $1.4 billion, approximately $250 million higher than 2010, despite realized natural gas prices that were 11% lower than the prior year. QEP Energy and QEP Field Services contributed $1.07 billion and $320 million, respectively. QEP Field Services 2011 Adjusted EBITDA contribution was 57% higher than 2010 and almost double that of 2009.

2011 Scorecard

- ✓ Generate $1.2 billion of QEP Resources Adjusted EBITDA
  Actual = $1.4 billion
- ✓ Grow production to 262 Bcfe with $1 billion of E&P CAPEX
  Actual = 275 Bcfe with $1.3 billion of CAPEX
- ✓ Replace 200% of production with proved developed finding and development costs of $2.40 per Mcfe or less
  Actual = Replaced 312% of production at $2.07 per Mcfe
- ✓ Achieve QEP Field Services Adjusted EBITDA of at least $200 million
  Actual = $320 million
- ✓ Complete and start-up Black Forks II processing plant in Q4 2011
  Actual = Black Forks II commenced operations in Q3 2011

FINANCIAL HIGHLIGHTS

($ in millions)

	2011	2010	2009	2008	2007	2006	5-YR CAGR
EBITDA*	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	$ 1,310.7	$ 890.7	$ 737.7	14%
Total Assets	**$ 7,442.7**	$ 6,785.3	$ 6,481.4	$ 6,342.7	$ 3,821.6	$ 3,261.8	18%
CAPEX	**$ 1,431.1**	$ 1,469.0	$ 1,198.4	$ 2,136.7	$ 838.9	$ 670.0	16%
Long-term Debt	**$ 1,679.4**	$ 1,530.8	$ 1,348.7	$ 1,299.1	$ 499.3	$ 399.2	33%
Total Equity	**$ 3,352.1**	$ 3,063.1	$ 2,808.7	$ 2,779.4	$ 1,860.1	$ 1,544.8	17%
Total Capitalization	**$ 5,031.5**	$ 4,593.9	$ 4,157.4	$ 4,078.5	$ 2,359.4	$ 1,944.0	21%
% Debt to Total Cap	**33.4%**	33.3%	32.4%	31.9%	21.2%	20.5%	N/A
Debt to EBITDA*	**1.2x**	1.3x	1.2x	1.0x	0.6x	0.5x	N/A

* Adjusted EBITDA

PRIMARY AREAS OF OPERATION

Letter To Shareholders

Dear Fellow QEP Shareholder,

For QEP Resources, 2011 was a year of transition and achievement. We completed our first full year as a standalone company and we welcomed many new shareholders as our ownership base continued to evolve following our spinoff from Questar in the summer of 2010. We continued our transition away from being predominantly a natural gas producer. In response to the commodity price environment last year, we allocated 68% of our drilling capital to crude oil and liquids-rich natural gas development at QEP Energy, our exploration and production business, and we accelerated completion and start-up of two important new NGL extraction facilities at QEP Field Services, our natural gas gathering and processing business.

The emphasis on crude oil and NGL projects in QEP Energy paid off in 2011. Crude oil and NGL production grew 54% from 2010 levels and accounted for 14% of QEP Energy's net production during the year. Year-end proved crude oil and NGL reserves more than doubled from year-end 2010 and accounted for 24% of QEP total proved reserves. Field Services' successful startup of the two new gas processing plants in the Northern Region during the year dramatically increased our production of NGL's and increased QEP Field Services total gas processing capacity to almost 1.4 Bcf per day.

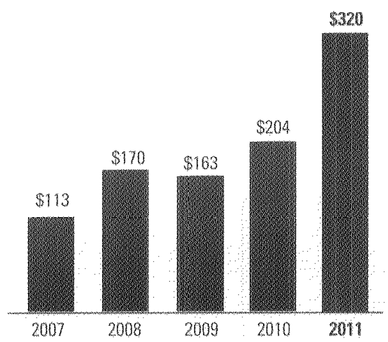
The impact of these achievements is evident in our financial results. Last year 40% of QEP Resources revenues resulted from the sale of crude oil and NGL's and from fees we collect in our gathering and processing business. We expect this transition to continue in 2012 and beyond as we allocate a greater percentage of our drilling capital to our higher-margin oil and liquids-rich gas resource plays in QEP Energy's deep portfolio of high quality assets, and as QEP Field Services continues to expand its gas processing capacity in response to growing volumes of liquids-rich gas production in its core areas of operation.

Record Financial and Operational Results

QEP Resources' Adjusted EBITDA was up 22% from last year, to a record $1.387 billion, driven by strong results at both QEP Energy and QEP Field Services. QEP Energy natural gas, crude oil and NGL production was up 20% from last year, to a record 275 Bcfe, driven by strong results from the Pinedale Anticline and Haynesville Shale plays, combined with significant contributions from new wells in our Woodford "Cana" Shale and Bakken/Three Forks plays. QEP Energy generated a record $1.058 billion of Adjusted EBITDA in 2011, a 14% increase over 2010. Field Services' Adjusted EBITDA increased 57%, to a record $320 million, almost double 2009's level. A combination of superb execution on the completion of the two new processing plants and strong margins in our gas processing business drove the excellent midstream results.

The profitability of our E&P business, QEP Energy, is driven by two basic factors: 1) the realized price of the products we sell; and 2) the cost of extracting these products from the ground. While the average field-level price of natural gas decreased to $3.95 per Mcf in 2011, compared to $4.18 per Mcf in 2010, our long-standing hedging program continued to increase natural gas price realizations. Derivative proceeds increased average net realized natural gas prices by $0.79 per Mcf in 2011. Field-level crude oil and NGL prices, on the other hand, improved dramatically compared to 2010. Field-level crude oil prices were $86.20 per barrel in 2011, up 24% compared to 2010. Derivative proceeds added $0.43 per barrel to 2011 crude oil price realizations. NGL prices also improved in 2011. Average field-level prices were up 22% from a year ago, to $47.76 per barrel. While prices were up, we were able to "hold the line" on costs. QEP Energy's cash cost of production - the sum of lease operating, general and administrative, interest expense and production taxes - was $1.56 in 2011, compared to $1.58 in 2010. Few companies have cash production costs lower than QEP Energy; we intend to maintain this competitive advantage!

QEP Field Services delivered outstanding results in 2011. The segment reported a record $320 million of Adjusted EBITDA in 2011, up a whopping 57% from $204 million a year ago. Field Services benefitted from growing gas volumes on its gathering systems and more importantly, from the startup of the two new gas plants that dramatically increased gas processing capacity and NGL sales volumes. The Iron Horse cryogenic gas processing plant, located in the Uinta Basin of eastern Utah, came on line in early January with a raw gas inlet capacity of 150 MMcf per day. July 2011 brought an ahead-of-schedule startup of the 420 MMcf per day Blacks Fork II cryogenic gas processing plant in July of 2011. Located in western Wyoming, the Blacks Fork II plant processes gas from the northern third of the Pinedale Anticline field – the largest natural gas field in the Rockies. The timing of the startup of these plants couldn't have been better. Low natural gas prices coupled with strong NGL prices led to exceptional gas processing margins in 2011, allowing us to recover a substantial portion of the capital we invested in these new facilities. Because Field Services' gas processing business improves in periods of lower natural gas prices, it also provides a natural hedge against price declines for a portion of QEP Energy's natural gas production.



Field Services Adjusted EBITDA
($ in millions)

QEP Energy

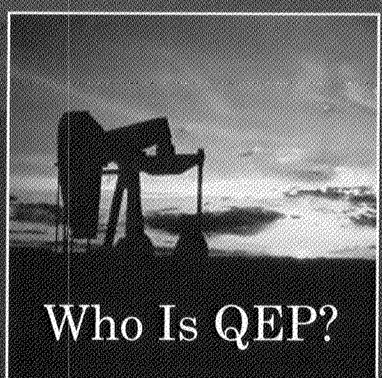
QEP Energy generated 76% of QEP Resources' 2011 Adjusted EBITDA. The company grew natural gas equivalent production 20% to a record 275 Bcfe. Our efforts to diversify our production mix toward more crude oil and liquids-rich gas plays continue to bear fruit. Thanks to strong results in our Bakken/ Three Forks crude oil play in the Williston Basin, combined with ongoing success in liquids-rich gas plays including Pinedale, the Cana Shale and Granite Wash, crude oil and NGL production totaled 6.5 million barrels in 2011, up 54% from a year ago.

QEP Energy's estimated proved reserves grew 19% to 3.6 Tcfe at year-end 2011, while the company replaced 312% of its 2011 production. Our focus on allocating capital to grow crude oil and NGL production also impacted year-end reserves. Crude oil and NGL comprised 24% of year-end 2011 estimated total proved reserves – a 107% increase over a year ago when liquids were only 14% of total proved reserves.

Pinedale Anticline — The Pinedale Anticline in western Wyoming is the largest gas field in the Rocky Mountain region. Pinedale remains one of the lowest cost gas fields in North America and QEP is the lowest cost producer in this field. Pinedale also remains QEP Energy's most valuable asset. At year-end 2011, QEP Energy reported proved reserves at Pinedale of 1.5 Tcfe. QEP leads the industry with low-cost drilling and completion costs at Pinedale, thanks to continued leadership in drilling and completion efficiency.

2011 Production
275 Bcfe

2011 Year-end Proved Reserves
3.6 Tcfe



QEP Resources, Inc. is a holding company which conducts business through three primary subsidiaries.

QEP Energy is a leading independent exploration and production company with proved reserves of 3.6 trillion cubic feet of gas equivalent, daily production of over 800 million cubic feet of gas equivalent and a track record of delivering a 16% compound annual growth rate in production over the past five years. Our asset managers have delivered this growth while maintaining one of the lowest cash cost structures in the E&P industry.

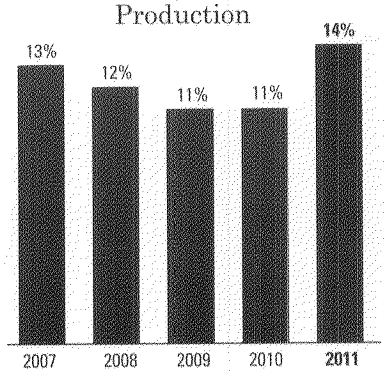
QEP Field Services gathers and processes natural gas production for QEP Energy and for other producers. QEP Field Services assets, located in the Rocky Mountain region and northwest Louisiana, include over 2,000 miles of gathering lines and natural gas processing capacity of 1.37 Bcf per day.

QEP Marketing sells QEP Energy and third party production to a variety of wholesale customers, manages gas pipeline transportation capacity, manages gas and oil price risk by entering into derivative transactions on behalf of QEP Energy and others and owns and operates a small underground gas storage field in western Wyoming.

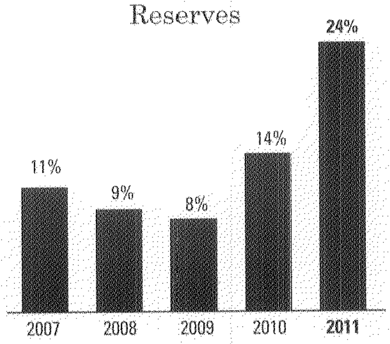
In 2011, we averaged just 13.8 days to drill a typical 14,300 foot Pinedale well from spud to total depth. That's down from a 17 day average in 2010 and 64 days back in 2004. Lower drill times translate directly into lower completed well costs. In 2011, QEP's gross completed well cost for a typical Pinedale well was $3.9 million, almost a million dollars less than our nearest competitor. We also have good visibility on future low-cost growth at Pinedale – QEP has up to 1,100 remaining locations to drill on a combination of 20, 10 and 5-acre density.

Bakken / Three Forks — The Bakken/Three Forks play in the Williston basin of North Dakota continues to gain importance as a source of domestic crude oil production, and QEP is right in the middle of the action. During 2011, QEP continued to delineate the eastern limit of our 90,000 net acre leasehold position in the North Dakota portion of the Bakken/Three Forks play and initiated pad-based development drilling on a portion of our acreage. The company operates 30 producing wells in the play, comprised of 24 Middle Bakken wells and 6 Three Forks wells, and has working interests in 93 additional wells operated by others.

Liquids as a Percentage of Total Production



Liquids as a Percentage of Total Reserves



Woodford "Cana" Shale — QEP Energy has 77,000 net acres in the expanding Woodford "Cana" Shale play in the Anadarko Basin of western Oklahoma. The company now operates 25 producing wells in the play and has interests in an additional 197 producing wells operated by other companies. Unlike many shale plays that are dominated by dry gas, Cana play economics are significantly enhanced by the revenue contribution of condensate and NGL's in the natural gas stream.

Tonkawa/Marmaton/Granite Wash — During 2011, there was a steep increase in horizontal drilling activity targeting crude oil reservoirs in the Tonkawa and Marmaton formations in western Oklahoma and the Texas Panhandle. Over the last year, QEP participated in seven new horizontal wells targeting the Marmaton Formation and 27 new horizontal wells targeting the Tonkawa Formation, with more planned for 2012 and beyond. In addition, horizontal wells targeting the liquids-rich reservoirs in the Granite Wash play in the Texas Panhandle and western Oklahoma continued to deliver strong results in 2011 with additional activity planned for 2012.

Uinta Mesaverde — The Mesaverde Formation in the Uinta Basin of eastern Utah is comprised of a series of stacked, discontinuous sands filled with liquids-rich gas and condensate. During 2011, QEP Energy commenced development of its over 32,000 net acre contiguous block of 100% owned and operated federal leasehold. Not only does this play have the potential to dramatically impact future QEP Energy production, it also presents QEP Field Services with significant future investment opportunities in gas gathering and processing infrastructure.

Haynesville Shale — There is no doubt that over the past several years, the Haynesville Shale in Northwest Louisiana has been one of the fastest growing natural gas producing regions in North America. QEP Energy has 50,800 net acres in the heart of the most prolific part of the play. During 2011, we completed our lease-saving drilling activity in this key play. In response to declining natural gas prices, we will dramatically reduce the capital allocated to Haynesville development drilling in 2012. With over 1,200 high quality development locations remaining in our inventory, the Haynesville remains a world-class natural gas asset and an important source of future growth for QEP when natural gas prices improve.

QEP Field Services

QEP Field Services generated 23% of QEP Resources' 2011 Adjusted EBITDA. Field Services gathers and processes natural gas for QEP Energy and third-party customers in the Rocky Mountain region and in northwest Louisiana. Field Services' assets are centered around and were built primarily to serve QEP Energy's core producing properties. Field Services' first priority remains the same today as it always has - to provide QEP Energy with high quality, cost-competitive gas gathering and processing services. While remaining true to that priority, through targeted expansions of gathering systems and processing plants, Field Services has built a vibrant third-party business. Today, almost 80% of Field Services revenues are derived from unaffiliated customers, and we are poised for future growth. Field Services has a deep inventory of gathering and processing projects. We just commenced construction on a new 150 MMcf per day cryogenic gas processing plant, Iron Horse II, located in the Uinta Basin of eastern Utah. Underpinned by both QEP and third-party volumes, we anticipate startup of this new plant in early 2013. We will soon break ground on a 10,000 barrel per day expansion of our existing 5,000 barrel per day NGL fractionator at Blacks Fork in western Wyoming. When complete in mid 2013, this expansion will allow additional marketing options for purity propane, normal and iso-butane, and gasoline products in high value regional and local markets.

Looking ahead to 2012 and beyond...

The success of the U.S. independent E&P industry at unlocking vast new supplies of natural gas from shale and other unconventional reservoirs continues to drive natural gas production to ever higher levels. Today, U.S. natural gas production exceeds 65 Bcf a day - a level never before achieved in the history of our industry. So much for the thesis that "we can't drill our way out of an energy shortage!" The resultant surge in supply, coupled with an exceptionally mild winter has led to record levels of natural gas in storage as we near the end of the heating season. While the decrease in natural gas prices has been a boon to U.S. consumers, it hasn't been so great for the U.S. natural gas industry or for your company. As I write this letter, the spot price of natural gas hovers around $2.30 per MMbtu and the consensus view is that the U.S. natural gas market is oversupplied by 3 to 4 Bcf per day.

While the near-term prospects for natural gas prices remain challenging, there are some glimmers of encouragement. First, while the number of drilling rigs working in the U.S. hovers around 2,000, for the first time in almost two decades the number of rigs drilling for oil exceeded that of rigs drilling for natural gas. In fact, over 65% of current drilling rig activity is directed toward crude oil development. As operators, including QEP, continue to redirect capital away from dry gas drilling activity, production levels will decline, but the response won't be instantaneous. Second, low natural gas prices are encouraging increased consumption of natural gas in the electric power generation sector and in many industrial and commercial markets. The "natural gas renaissance" powered by abundant new resources of clean-burning domestic natural gas has breathed new life into many American industries, from steelmaking to petrochemicals. With time, supply and demand will balance, and natural gas prices will improve. The question is not if prices will improve, but when. The good news is that QEP's cost leadership, our emphasis on a long-term investment horizon, and our high quality asset base allow us to make money, even at today's prices.

How is your company responding to this challenging environment? Our strategy remains the same today as it has for many years. We will continue to deliver strong financial results through a focus on superior execution, on being a low-cost driller and producer, on returns-driven capital allocation, and on living within our means. This process drives our strategy and hence our 2012 plan:

1. Set a capital investment program that matches our projected 2012 Adjusted EBITDA.
2. Allocate capital to the highest return projects in our portfolio. In the current commodity price and well cost environment, this means we will allocate over 85% of our 2012 development drilling capital at QEP Energy to crude oil and liquids-rich gas plays.
3. Continue to drive down drilling and completion cycle times and completed well costs.
4. Continue to expand our gas gathering and processing infrastructure in Field Services.
5. Maintain a strong balance sheet.
6. Maximize the value of every molecule we produce through safe and efficient operations.

If we execute efficiently, we should continue to increase the percentage of crude oil and NGL to over 20% of QEP Energy's production in 2012, up from 14% in 2011.

In Conclusion

As we look toward the future, I continue to believe that QEP has some of the lowest cost, highest quality upstream and midstream assets in North America. But high quality assets don't guarantee success. We also have some of the most creative, innovative and hardest-working women and men in the industry managing these assets. QEP employees maintain

2012 Goals

- Maximize our Health, Safety, and Environmental (HSE) performance through an increased focus on our HSE organization, policies, standards, systems, performance measurements and reporting
- Generate $1.4 billion of QEP Resources Adjusted EBITDA
- Grow production to 307 Bcfe with $1.2 billion of E&P CAPEX
- Increase liquids production to over 20% of total net production, up from 14% in 2011
- Achieve QEP Field Services Adjusted EBITDA of at least $320 million

a keen focus on safe and reliable operations, on minimizing our environmental impact, and on actively supporting the communities in which we live and work. My thanks to each of them for all we have accomplished. With their continued support and efforts, I am confident we will go far.

On behalf of QEP's board, management, and dedicated employees, thank you for your investment in our company. We manage this business for you, and we come to work every day mindful of the trust that you place in us when you buy our shares.

Sincerely,

Charles B. Stanley
President and Chief Executive Officer

QEP Resources, Inc.

10K / FINANCIALS

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the Year Ended December 31, 2011

QEP Resources, Inc.

QEP RESOURCES, INC.
(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	001-34778	87-0287750
(State or other jurisdiction of incorporation)	(Commission File No.)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 500, Denver, Colorado 80265
(Address of principal executive offices)

Registrant's telephone number, including area code: 303-672-6900

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, $0.01 par value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. (June 30, 2011): $7,399,937,572.

At January 31, 2012, there were 177,498,486 shares of the registrant's $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's Definitive Proxy Statement for its 2011 Annual Meeting of Stockholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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Where You Can Find More Information

QEP Resources, Inc. (QEP or the Company) files annual, quarterly, and current reports with the Securities and Exchange Commission (SEC). Prior to QEP's Spin-off from Questar Corporation (described in more detail in the Explanatory Note in Item 1 of Part I of this Annual Report on Form 10-K), QEP's predecessor, Questar Market Resources, Inc., filed annual, quarterly and current reports with the SEC. QEP also regularly files proxy statements and other documents with the SEC. These reports and other information can be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549-0213. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. The SEC also maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including QEP.

Investors can also access financial and other information via QEP's website at www.qepres.com. QEP makes available, free of charge through the website, copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports and all reports filed by executive officers and directors under Section 16 of the Exchange Act reporting transactions in QEP securities. Access to these reports is provided as soon as reasonably practical after such reports are electronically filed with the SEC. Information contained on or connected to QEP's website which is not directly incorporated by reference into the Company's Annual Report on Form 10-K should not be considered part of this report or any other filing made with the SEC.

QEP's website also contains copies of charters for various board committees, including the Audit Committee, Corporate Governance Guidelines and QEP's Business Ethics and Compliance Policy.

Finally, you may request a copy of filings other than an exhibit to a filing unless that exhibit is specifically incorporated by reference into that filing, at no cost by writing or calling QEP, 1050 17th Street, Suite 500, Denver, CO 80265 (telephone number: 1-303-672-6900).

Forward-Looking Statements

This Annual Report contains or incorporates by reference information that includes or is based upon "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. We use words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- QEP's growth strategies;
- plans to drill or participate in wells;
- future expenses and operating costs;
- belief that QEP has one of the lowest cash cost structures among its peers;
- the outcome of contingencies such as legal proceedings;
- expected contributions to the Company's retirement plans;
- results from planned drilling operations and production operations;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures;
- impact of recently issued accounting pronouncements;
- the amount and timing of the settlement of derivative contracts;
- the significance of Adjusted EBITDA as a measure of cash flow and liquidity;
- the ability of QEP to use derivative instruments to manage commodity price risk;
- the ability to secure long-term gathering, processing and treating contracts from third parties as required to fully utilize the Company's midstream assets;
- operation of the Company's Blacks Fork II and other processing plants at assumed capacities;
- QEP's ability to develop reserves and grow production as necessary to satisfy delivery commitments and our ability to purchase natural gas, crude oil and NGL's in the market to cover any shortfalls;

- payment of dividends;
- plans to hedge a portion of forecasted production;
- conversion of proved undeveloped reserves to proved developed reserves;
- acquisition strategy; and
- growth strategy.

Any or all forward-looking statements may turn out to be incorrect. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. These statements are based on current expectations and the current economic environment. They involve a number of risks and uncertainties that are difficult to predict. These statements are not guarantees of future performance. Actual results could differ materially from those expressed or implied in the forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to the following:

- the risk factors discussed in Part I, Item 1A of this Annual Report;
- changes in natural gas, oil and NGL prices;
- general economic conditions, including the performance of financial markets and interest rates;
- drilling results;
- shortages of oilfield equipment, services and personnel;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- changes in industry trends;
- the availability and cost of debt financing;
- changes in laws or regulations, including the implementation of the Dodd-Frank Act;
- actions, or inaction, by federal, state, local or tribal governments; and
- other factors, most of which are beyond the Company's control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Annual Report, in other documents, or on the website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

Glossary of Commonly Used Terms

B Billion.

bbl Barrel, which is equal to 42 U.S. gallons and is a common measure of volume of crude oil and other liquid hydrocarbons.

basis The difference between a reference or benchmark commodity price and the corresponding sales price at various regional sales points.

basis-only swap A derivative that "swaps" the basis (defined above) between two sales points from a floating price to a fixed price for a specified commodity volume over a specified time period. Typically used to fix the price relationship between a geographic sales point and a NYMEX reference price.

Btu One British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

cash flow hedge A derivative instrument that complies with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 815 and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas and oil production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

cf Cubic foot or feet is a common unit of gas measurement. One standard cubic foot equals the volume of gas in one cubic foot measured at standard conditions – a temperature of 60 degrees Fahrenheit and a pressure of 30 inches of mercury (approximately 14.7 pounds per square inch).

cfe Cubic foot or feet of natural gas equivalents.

cushion gas Volume of gas that must remain in a storage facility to provide the required pressure to extract the stored or working gas volumes.

developed reserves Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. See 17 C.F.R. Section 4-10(a)(6).

development well A well drilled into a known producing formation in a previously discovered field.

dry hole A well drilled or junked and abandoned and found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed expenses and taxes.

exploratory well A well drilled into a previously untested geologic prospect to determine the presence of gas or oil.

frac spread The difference between the market value for natural gas liquids (NGL) extracted from the natural gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids.

gas All references to "gas" in this report refer to natural gas.

gross "Gross" natural gas and oil wells or "gross" acres are the total number of wells or acres in which the Company has a working interest.

hedging The use of commodity and interest-rate derivative instruments to reduce financial exposure to commodity price and interest-rate volatility.

IFNPCR Inside FERC monthly settlement index for the Northwest Pipeline Corp. Rocky Mountains.

IFPEPL Inside FERC monthly settlement index for the Panhandle Eastern Pipeline Company.

M Thousand.

MM Million.

Midstream Gas gathering, compression, treating, processing, and transmission assets and activities that are non-jurisdictional. Also includes certain oil and produced water gathering systems and related commercial activities.

natural gas equivalents Oil and NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil, condensate or NGL to 6,000 cubic feet of natural gas.

natural gas liquids (NGL) Liquid hydrocarbons that are extracted from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and heavier hydrocarbons.

net "Net" gas and oil wells or "net" acres are determined by the sum of the fractional ownership working interest the Company has in the gross wells or acres.

NYMEX The New York Mercantile Exchange.

NYMEX WTI The price of West Texas Intermediate crude oil on the New York Mercantile Exchange.

proved reserves Those quantities of natural gas, oil, condensate and NGL which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. See 17 C.F.R. Section 4-10(a)(22).

reserves Estimated remaining quantities of natural gas, oil and related substances anticipated to be economically producible by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce. See 17 C.F.R. Section 4-10(a)(26).

reservoir A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

royalty An interest in a gas and oil lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the minerals at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

seismic data/survey An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

T Trillion.

undeveloped reserves Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 4-10(a)(31).

working interest An interest in a gas and oil lease that gives the owner the right to drill, produce and conduct operating activities on the leased acreage and receive a share of any production.

PART I

ITEM 1. BUSINESS

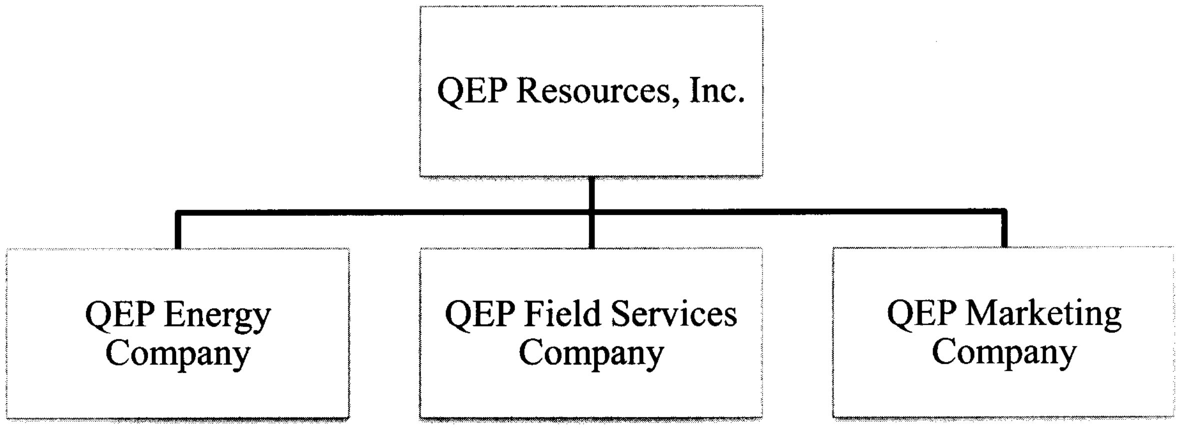
Nature of Business

QEP Resources, Inc. (QEP or the Company), is a holding company with three major lines of business – gas and oil exploration and production, midstream field services, and energy marketing –conducted through three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and natural gas liquids (NGL);
- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering, processing, compression and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

QEP operates in the Northern (formerly referred to as the Rocky Mountain Region) and Southern (formerly referred to as the Midcontinent Region) Regions of the United States and is headquartered in Denver, Colorado. Principal offices are located in Denver, Colorado; Salt Lake City, Utah; Oklahoma City, Oklahoma; and Tulsa, Oklahoma.

The corporate-organization structure and principal subsidiaries are depicted below:



Reincorporation Merger and Spin-off from Questar

Effective May 18, 2010, Questar Market Resources Inc., (Market Resources), then a wholly owned, public subsidiary of Questar Corporation (Questar), merged with and into a newly formed, wholly owned subsidiary, QEP Resources, Inc., a Delaware corporation in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. On June 30, 2010, Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spin-off). Each Questar shareholder received one share of QEP common stock for each share of Questar common stock held at the close of business on the record date. In connection with the Spin-off, QEP distributed Wexpro Company (Wexpro), a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

In connection with the reorganization, QEP renamed its subsidiaries as follows:

- QEP Energy Company (formerly Questar Exploration and Production Company),
- QEP Field Services Company (formerly Questar Gas Management Company), and
- QEP Marketing Company (formerly Questar Energy Trading Company).

The financial information presented in this Form 10-K presents QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 2 to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

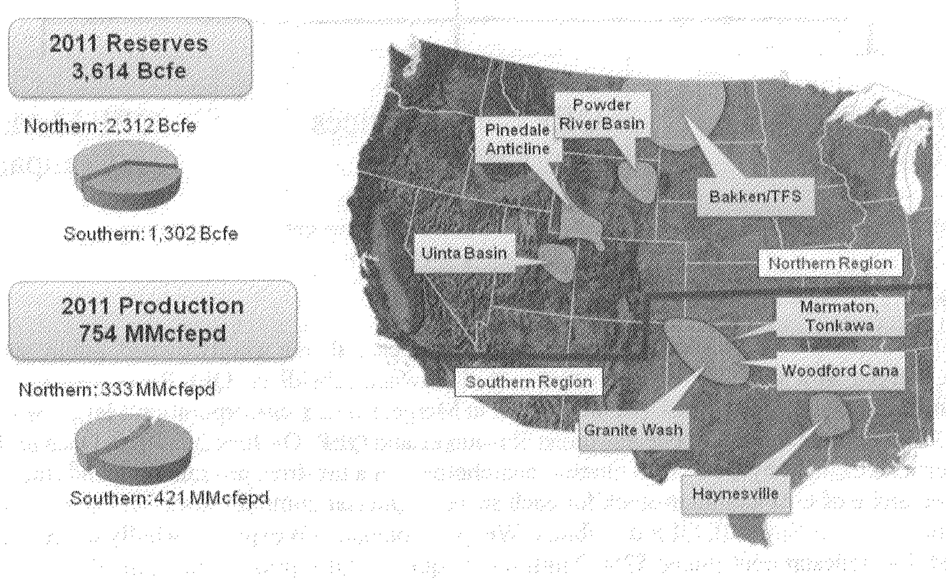
Strategies

We create value for our shareholders through returns-focused growth, superior execution, and a low cost structure. To achieve these objectives we will strive to:

- Operate in a safe and environmentally responsible manner
- Allocate capital to the projects that generate the best returns
- Maintain a sustainable inventory of low-cost, high margin resource plays
- Be in the best parts of the plays in which we operate
- Build contiguous acreage positions to drive efficiencies
- Be the operator of our assets whenever possible
- Be the low-cost driller and producer in each area where we operate
- Own and operate midstream infrastructure in our core producing areas to control our future and capture value downstream of the wellhead
- Build gas processing plants to extract liquids from our gas streams
- Gather, compress and treat our production to drive down costs
- Actively market our QEP Energy production to maximize value
- Utilize commodities derivatives to reduce the impact of a decline in the prices of our natural gas, crude oil or NGL and to lock in acceptable cash flows to support future capital expenditures
- Attract and retain the best people
- Maintain a strong balance sheet and financial flexibility that allows us to take advantage of both organic growth and acquisition opportunities

EXPLORATION AND PRODUCTION – QEP Energy Company

General: QEP Energy is actively involved in several of North America's most important hydrocarbon resource plays. For 2012, QEP plans to allocate approximately 88% of its capital budget to QEP Energy. The following map illustrates the location of the Company's significant exploration and production activities, our Northern and Southern Regions described elsewhere in this report, and related reserve and production data:



QEP's exploration and production activities are conducted through QEP Energy, which generated approximately 76%, 81%, and 85% of the Company's Adjusted EBITDA during the years ended December 31, 2011, 2010 and 2009, respectively. QEP Energy operates in two core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, New Mexico and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana). The Southern Region contributed approximately 56% of 2011 production while the Northern Region contributed the remaining 44%. QEP Energy reported 3,614 Bcfe of estimated proved reserves as of December 31, 2011, up from 3,031 Bcfe at the end of 2010. Of those estimated proved reserves, approximately 64%, or 2,312 Bcfe, were located in the Northern Region at December 31, 2011, compared to 61% or 1,860 Bcfe at December 31, 2010. The remaining 36%, or 1,302 Bcfe at December 31, 2011, were located in the Southern Region, compared to 39% or 1,171 Bcfe at

December 31, 2010. Approximately 54% of the proved reserves reported by QEP Energy at year end 2011 were developed, while 46% were categorized as proved undeveloped. Approximately 24% of the total proved reserves at December 31, 2011 were comprised of crude oil and NGL up from 14% at December 31, 2010.

QEP Energy has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming; the Haynesville/Cotton Valley area in northwestern Louisiana; the Midcontinent area with properties primarily in Oklahoma and Texas; the Uinta Basin in eastern Utah; and the Rockies Legacy, which includes the Bakken/Three Forks area in western North Dakota and other properties in Wyoming. QEP Energy continues to conduct exploratory drilling to determine the commerciality of its inventory of unproven leaseholds. The Company seeks to acquire, develop and produce natural gas and oil from so-called "resource plays" in its core areas. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs. Since the existence and distribution of hydrocarbons in resource plays is well understood, development of these accumulations has lower risk than conventional discrete hydrocarbon accumulations. Resource plays typically require many wells, drilled at high density, to fully develop and produce the hydrocarbon accumulations. Development of QEP Energy's resource play accumulations requires expertise in drilling large numbers of complex, highly deviated or horizontal wells to vertical depths that generally range between 10,000 and 14,000 feet and the application of advanced well completion techniques, including hydraulic fracture stimulation, to achieve economic production. QEP Energy seeks to maintain geographical and geological diversity with its two core regions. The Company has in the past and may in the future pursue acquisition of producing properties through the purchase of assets or corporate entities to expand its presence in its core areas or to create new core areas.

Competition and Customers: QEP Energy faces competition in every part of its business, including the acquisition of producing leasehold and wells and undeveloped leasehold, the marketing of natural gas and oil, and obtaining goods, services and labor. Its longer-term growth strategy depends, in part, on its ability to acquire reasonably-priced acreage containing undeveloped reserves and identify and develop them in a low-cost and efficient manner.

QEP Energy, both directly and through QEP Marketing, sells natural gas production to a variety of customers, including gas-marketing firms, industrial users and local-distribution companies. QEP Energy regularly evaluates counterparty credit and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Regulation: QEP Energy operations are subject to extensive government controls and regulation at the federal, state and local levels. QEP Energy must obtain permits to drill and produce wells; maintain required bonds to drill and operate wells; submit and implement spill-prevention plans; and file notices relating to the presence, use, and release of specified contaminants in air and water emissions and discharges incidental to gas and oil drilling, completion and production. QEP Energy is also subject to various conservation matters, including regulation of the size of drilling and spacing units, the number of wells that may be drilled in a unit and the unitization or pooling of gas and oil properties. Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of natural gas and oil well design and operation. Most of QEP Energy's leasehold acreage in the Northern Region is held under leases granted by the United States and administered by federal agencies, principally the Bureau of Land Management (BLM). Current federal regulations restrict activities during certain times of the year on significant portions of QEP Energy leasehold due to wildlife activity and/or habitat. QEP Energy has worked with federal and state officials in Wyoming to obtain authorization for limited winter-drilling activities on the Pinedale Anticline and has developed measures, such as drilling multiple wells from a single pad location, to minimize the impact of its activities on wildlife and wildlife habitat. Various wildlife species inhabit QEP Energy leaseholds at Pinedale and in other areas. The presence of wildlife or plants, including species and types that are protected under the Federal Endangered Species Act, could limit access to leases held by QEP Energy on public lands.

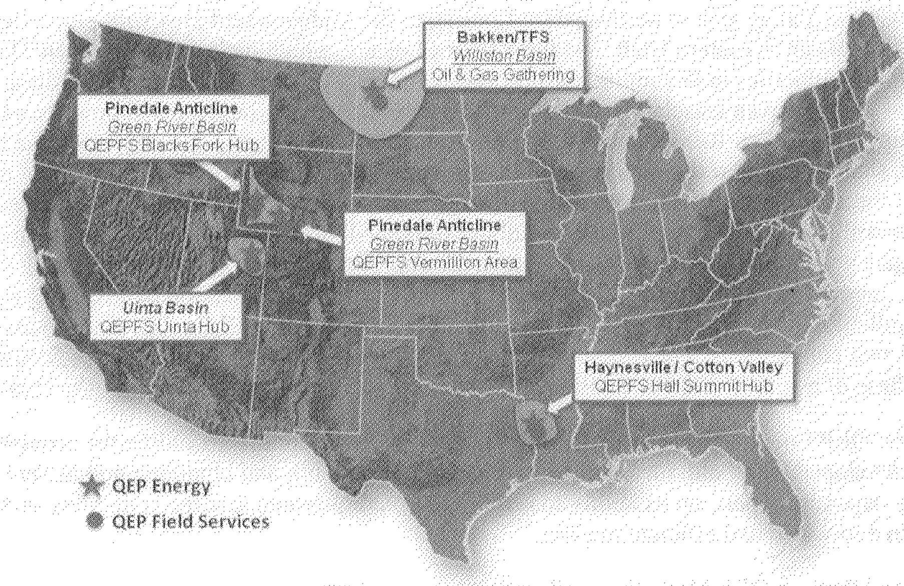
In September 2008, the BLM issued a Record of Decision (ROD) on the Final Supplemental Environmental Impact Statement (FSEIS) for long-term development of natural gas resources in the Pinedale Anticline Project Area (PAPA). Under the ROD, QEP Energy is allowed to drill and complete wells year-round in one of five Concentrated Development Areas defined in the PAPA. The ROD contains additional requirements and restrictions on development of the PAPA.

See also "Risk Factors – Risk Related to Regulation."

MIDSTREAM FIELD SERVICES – QEP Field Services Company

General: QEP invests in midstream (gathering, processing and treating) systems to complement its natural gas, oil and NGL operations in regions where QEP Energy has production. Through ownership and operation of these facilities, QEP is able to better manage the timing and costs associated with bringing on new production and enhance the value received for gathering, processing and treating the Company's production. In addition, QEP's midstream business also provides midstream services to third-party customers, including major and independent producers. QEP generates revenues from its midstream activities through a variety of agreements including fixed-fee, percent-of-proceeds and keep-whole agreements. For 2012, QEP plans to allocate approximately 12% if its capital budget to QEP Field Services.

The following map illustrates QEP Field Services areas of operations and the locations corresponding with QEP Energy's operating areas:



QEP Field Services generated approximately 23%, 18% and 14% of the Company's Adjusted EBITDA in the years ended December 31, 2011, 2010 and 2009, respectively. QEP Field Services owns various natural gas gathering, treating and processing facilities in the Northern and Southern Regions as well as 78% of Rendezvous Gas Services, LLC, (RGS), a partnership that operates gas gathering facilities in western Wyoming. The FERC-regulated Rendezvous Pipeline Co., LLC (Rendezvous Pipeline), a wholly owned subsidiary of QEP Field Services, operates a 21-mile, 20-inch-diameter pipeline between QEP Field Services' Blacks Fork gas-processing plant and the Muddy Creek compressor station owned by Kern River Gas Transmission Co. (Kern River Pipeline). RGS gathers natural gas for Pinedale Anticline and Jonah Field producers for delivery to various interstate pipelines. QEP Field Services also owns 38% of Uintah Basin Field Services, LLC (UBFS) and 50% of Three Rivers Gathering, LLC (Three Rivers). These two partnerships operate natural gas gathering facilities in eastern Utah.

Fee-based gathering and processing revenues were 70%, 78% and 82% of QEP Field Services' net operating revenues (revenues less plant shrink and transportation costs) during the years ended December 31, 2011, 2010 and 2009, respectively. Approximately 35%, 36%, and 43% of QEP Field Services' 2011, 2010 and 2009 net gas processing revenues (processing revenues less plant shrink and transportation costs) were derived from fee-based processing agreements. The remaining revenues were derived from keep-whole processing agreements. A keep-whole contract exposes QEP Field Services to frac-spread risk while a fee-based contract eliminates commodity price exposure. To further reduce volatility associated with keep-whole contracts, QEP Field Services may enter into forward-sales contracts for NGL or hedge NGL prices and equivalent gas volumes with the intent to lock in a processing margin.

Competition and Customers: QEP Field Services faces regional competition with varying competitive factors in each basin. QEP Field Service's gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. Numerous factors impact a customer's choice of a gathering or processing services provider, including rate, location, term, pressure obligations, timeliness of services, and contract structure. QEP Field Services provides natural gas gathering, processing and treating services to affiliates and third-party producers who own producing natural gas fields in the Rocky Mountain region and in northwest Louisiana. Most of QEP Field Services' gas gathering, processing and treating services are provided under long-term agreements.

Regulation: QEP Field Services' construction and operation activities are subject to various local, state and federal rules and regulations. Most of these rules and regulations are administered by the federal Department of Transportation (DOT), the Occupational Safety and Health Administration (OSHA), and the Environmental Protection Agency (EPA). Many of QEP's systems in the Northern Region are constructed and operated on public lands owned by the United States and administered by the Bureau of Land Management (BLM). Construction and operation of facilities on non-public land may also be subject to various regulations administered by state, tribal or local authorities.

Section 1(b) of the Natural Gas Act exempts gathering activities from regulation or jurisdiction by the Federal Energy Regulatory Commission (FERC). QEP owns, or holds interests in, a number of pipelines that it believes meet the tests FERC has used to determine a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining jurisdictional status of our gathering systems, so the distinction between non-jurisdictional gathering and FERC-regulated transmission pipelines may from time-to-time be the subject of disputes and litigation. QEP therefore cannot guarantee that the jurisdictional status of its gathering systems will remain unchanged. Several of QEP's facilities have been determined to be under FERC jurisdiction and as such are subject to specific regulations regarding interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination, and public daily capacity and flow reporting requirements. QEP's gas gathering systems are not subject to state utility regulations.

Additional rules and regulations pertaining to QEP Field Services activities are adopted from time to time. QEP cannot predict what impact, if any, such rules and regulations might have on its operations, but QEP may be forced to incur additional capital expenditures and/or increased operating costs as a result of such changes.

See also "Risk Factors – Risk Related to Regulation."

ENERGY MARKETING—QEP Marketing Company

General: QEP Marketing provides wholesale marketing and sales of affiliate and third-party natural gas, oil and NGL and generated approximately 1%, of the Company's Adjusted EBITDA in the years ended December 31, 2011, 2010 and 2009, respectively. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains, Pacific Northwest and Midcontinent that are either close to affiliate reserves and production or accessible by major pipelines. QEP Marketing contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin, a large baseload-storage facility.

QEP Marketing, through its subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir in southwestern Wyoming. QEP Marketing uses owned and leased storage capacity together with firm-transportation capacity to manage seasonal swings in prices in the Rocky Mountain region.

Competition and Customers: QEP Marketing competes directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. QEP Marketing also competes with brokerage houses, energy hedge funds and other energy-based companies offering similar services. QEP Marketing sells QEP Energy natural gas and volumes purchased from third parties to wholesale marketers, industrial end-users and utilities. QEP Marketing sells QEP Energy crude oil volume to refiners, remarketers and other companies, including some with pipeline facilities near company producing properties. QEP Marketing sells NGL volumes from its Clear Creek storage facility to a refiner. In the event pipeline facilities are not available, QEP Marketing arranges transportation of crude oil by truck or rail to storage, refining or pipeline facilities. QEP Marketing uses derivative instruments to manage commodity price risk, on behalf of QEP Energy and QEP Field Services, using fixed-price swaps or collars to secure a known price or price floor for a specific volume of production. QEP Marketing does not engage in speculative hedging transactions. See Item 7A and Notes 1 and 7 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for additional information relating to hedging activities.

Regulation: The U.S. Commodities Future Trading Commission, which has regulatory authority over swap transactions under the Dodd-Frank Act, has adopted various rules which impose compliance requirements upon QEP Marketing's derivatives trading practices. *See* also "Risk Factors – Risks Related to Regulation."

FERC has jurisdiction over the operation of QEP Marketing's Clear Creek storage facility, through the Clear Creek Storage Company LLC subsidiary in which QEP Marketing is the sole member, by virtue of the facility being connected to interstate pipelines (also subject to FERC jurisdiction) at both its inlet and outlet. Clear Creek is subject to specific FERC regulations governing interstate transmission facilities and activities, including but not limited to rates charges for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows.

Employees

At December 31, 2011, QEP Resources, Inc. had 876 employees compared to 823 employees at December 31, 2010. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 24, 2012, are listed below:

Charles B. Stanley	53	President, Chief Executive Officer, QEP (2010 to present). Previous titles with Questar: Chief Operating Officer (2008 to 2010); Executive Vice President and Director (2003 to 2010); President, Chief Executive Officer and Director, Market Resources and Market Resources subsidiaries (2002 to 2010).

Richard J. Doleshek	53	Executive Vice President and Chief Financial Officer, QEP (2010 to present). Previous titles with Questar: Executive Vice President and Chief Financial Officer (2009 to 2010). Prior to joining Questar, Mr. Doleshek was Executive Vice President and Chief Financial Officer, Hilcorp Energy Company (2001 to 2009).
Jay B. Neese	53	Executive Vice President, QEP (2010 to present). Previous titles with Questar: Senior Vice President (2005 to 2010); Executive Vice President, Market Resources and Market Resources subsidiaries (2005 to 2010); Vice President, Market Resources and Market Resources subsidiaries (2003 to 2005); Assistant Vice President (2001 to 2003).
Perry H. Richards	51	Senior Vice President – Field Services (2010 to present). Previous title with Questar: Vice President, Questar Gas Management (2005 to 2010).
Eric L. Dady	57	Vice President and General Counsel, QEP (2010 to present). Previous title with Questar: General Counsel Market Resources (2005 to 2010).
Abigail L. Jones	51	Vice President, Compliance, Corporate Secretary and Assistant General Counsel, QEP (2010 to present). Previous titles with Questar: Vice President Compliance (2007 to 2010); Corporate Secretary (2005 to 2010); Assistant Secretary (2004 to 2005).

There is no "family relationship" between any of the listed officers or between any of them and the Company's directors. The executive officers serve at the pleasure of the Board of Directors. There is no arrangement or understanding under which the officers were selected.

ITEM 1A. RISK FACTORS

Investors should read carefully the following factors as well as the cautionary statements referred to in "Forward-Looking Statements" herein. If any of the risks and uncertainties described below or elsewhere in this Annual Report actually occur, the Company's business, financial condition or results of operations could be materially adversely affected.

Risks Inherent in the Company's Business

The prices for natural gas, oil and NGL are volatile, and a decline in such prices could adversely affect QEP's results, stock price and growth plans. Historically natural gas, oil and NGL prices have been volatile and will likely continue to be volatile in the future. U.S. natural gas prices in particular are significantly influenced by weather. Any significant or extended decline in commodity prices would impact the Company's future financial condition, revenue, operating results, cash flow, return on invested capital, and rate of growth. In addition, significant and extended declines in commodity prices could limit QEP's access to sources of capital or cause QEP to delay or postpone some of its capital projects. Because a significant portion of QEP Energy's future production is natural gas, the Company's financial results are substantially more sensitive to changes in natural gas prices than to changes in oil prices.

QEP cannot predict the future price of natural gas, oil and NGL because of factors beyond its control, including but not limited to:

- changes in domestic and foreign supply of natural gas, oil and NGL;
- changes in local, regional, national and global demand for natural gas, oil, NGL and related commodities;
- the activities of the Organization of Petroleum Exporting Countries;
- domestic and global economic conditions;
- regional price differences resulting from available pipeline transportation capacity or local demand;
- terrorist attacks on production or transportation assets;
- the level of imports of, and the price of, foreign natural gas, oil and NGL;
- the potential long-term impact of an abundance of natural gas from unconventional sources on the global gas supply;
- domestic political developments and actions;
- weather conditions;
- domestic government regulations and taxes, including regulations or legislation relating to climate change or natural gas and oil exploration and production activities;
- technological advances affecting energy consumption and energy supply;
- conservation efforts;
- the price, availability and acceptance of alternative fuels, including coal, nuclear energy and biofuels;
- demand for electricity as well as natural gas used for fuel for electricity generation;
- storage levels of natural gas, oil, and NGL; and
- the quality of natural gas and oil produced.

In addition, lower commodity prices may result in asset impairment charges from reductions in the carrying values of QEP's natural gas and oil properties or a reduction in the carrying value of goodwill. During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of QEP Energy's mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. See Item 8, footnote 1, "Summary of Significant Accounting Policies" for additional information.

Slower economic growth rates in the US may materially adversely impact QEP's operating results. The US and other economies are recovering from a global financial crisis and recession that began in 2008. Growth has resumed but has been modest and at an unsteady rate. There are likely to be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than what was experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved. In addition, the Organization for Economic Cooperation and Development (OECD) has encouraged countries with large federal budget deficits, such as the US, to initiate deficit reduction measures. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate is likely to result in decreased demand growth for QEP's natural gas, oil and NGL production. A decrease in demand, excluding changes in other factors, could potentially result in lower commodity prices, which would reduce QEP's cash flows from operations and its profitability.

The Company may not be able to economically find and develop new reserves. The Company's profitability depends not only on prevailing prices for natural gas, oil and NGL, but also its ability to find, develop and acquire gas and oil reserves that are economically recoverable. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because natural gas and oil production volumes from QEP wells typically decline by 60% or more in the first year of operation and continue to decline over the economic life of the well, QEP must continue to invest significant capital to find, develop and acquire gas and oil reserves to replace those depleted by production.

Gas and oil reserve estimates are imprecise and subject to revision. QEP's proved natural gas and oil reserve estimates are prepared annually by independent reservoir-engineering consultants. Gas and oil reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and timing of development expenditures. The accuracy of these estimates depends on the quality of available data and on engineering and geological interpretation and judgment. Reserve estimates are imprecise and will change as additional information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers, or by the same engineers at different times, may vary significantly. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimation process also involves economic assumptions relating to commodity prices, operating costs, severance and other taxes, capital expenditures and remediation costs. Actual results most likely will vary from the estimates. Any significant variance from these assumptions could affect the recoverable quantities of reserves attributable to any particular properties, the classifications of reserves, the estimated future net cash flows from proved reserves and the present value of those reserves.

Investors should not assume that QEP's presentation of the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves in this Annual Report is the current market value of the estimated natural gas and oil reserves. In accordance with SEC disclosure rules, the estimated discounted future net cash flows from QEP's proved reserves are based on the first-of-the-month prior 12-month average prices and current costs on the date of the estimate, holding the prices and costs constant throughout the life of the properties and using a discount factor of 10 percent per year. Actual future prices and costs may differ materially from those used in the current estimate, and future determinations of the Standardized Measure of Discounted Future Net Cash Flows using similarly determined prices and costs may be significantly different from the current estimate.

Shortages of oilfield equipment, services and qualified personnel could impact results of operations. The demand for and availability of qualified and experienced field personnel to drill wells and conduct field operations, including geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. There have also been regional shortages of drilling rigs and other equipment, as demand for specialized rigs and equipment has increased along with the number of wells being drilled. These factors also cause increases in costs for equipment, services and personnel. These cost increases could impact profit margin, cash flow and operating results or restrict the ability to drill wells and conduct operations, especially during periods of lower natural gas and oil prices.

QEP's operations involve numerous risks that might result in accidents and other operating risks and costs. Drilling of natural gas and oil wells is potentially a high-risk activity. Risks include:

- fire, explosions and blow-outs;
- unexpected drilling conditions such as abnormally pressured formations;
- pipe, cement or casing failures;
- plant, pipeline, and other facility accidents and failures; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine water or well fluids (including groundwater contamination).

The Company could incur substantial losses as a result of injury or loss of life; pollution or other environmental damage; damage to or destruction of property and equipment; regulatory investigation; fines or curtailment of operations; or attorney's fees and other expenses incurred in the prosecution or defense of litigation. As a working interest owner in wells operated by other companies, the Company may also be exposed to the risks enumerated above that are not within its care, custody or control.

There are also inherent operating risks and hazards in the Company's gas and oil production and gas gathering, processing and treating operations that could cause substantial financial losses. In addition, these risks could result in personal injury or loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites could increase the level of damages resulting from these risks. Certain segments of the Company's pipelines run through such areas. In spite of the Company's precautions, an accident or other event could cause considerable harm to people or property, and could have a material adverse effect on the financial position and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks once realized could further result in lost business activity. Such circumstances could adversely impact the Company's ability to meet contractual obligations.

As is customary in the gas and oil industry, the Company maintains insurance against some, but not all, of these potential risks and losses. Although QEP believes the coverage and amounts of insurance that it carries are consistent with industry practice, QEP does not have insurance protection against all risks that it faces, because QEP chooses not to insure certain risks, insurance is not available at a level that balances the costs of insurance and QEP's desired rates of return, or actual losses exceed coverage limits. Losses and liabilities arising from uninsured or underinsured events could have a material adverse effect on QEP's financial condition, results of operations and cash flows.

Lack of availability of pipeline capacity could impact results of operations. The lack of availability of satisfactory oil, natural gas and NGL transportation arrangements may hinder QEP's access to oil, NGL and natural gas markets or delay production from its wells. QEP's ability to market its production depends in substantial part on the availability and capacity of pipelines owned and operated by third parties. Although QEP has some contractual control over the transportation of its production through firm transportation arrangements, third-party systems may be temporarily unavailable due to market conditions, mechanical failures, or other reasons. If pipelines do not exist near producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, sales could be reduced or production shut in, reducing profitability. Furthermore, if QEP were required to shut in wells, it might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain its leases. If pipeline quality requirements change, QEP might be required to install additional treating or processing equipment, which could also increase costs. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could also adversely affect QEP's ability to transport natural gas and oil.

The fees charged to third parties under our gathering and processing agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances. QEP's costs may increase at a rate greater than the fees it charges to third parties for gathering, treating and processing services. Furthermore, third parties may not renew their contracts with QEP. Additionally, some third parties' obligations under their agreements with QEP may be permanently or temporarily reduced due to certain events, some of which are beyond QEP's control, including force majeure events wherein the supply of either natural gas, oil or NGLs are curtailed or cut off. Force majeure events include (but are not limited to): revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, earthquakes, acts of God, explosions and mechanical or physical failures of equipment affecting QEP's facilities or facilities of third parties. If the escalation of fees is insufficient to cover increased costs, if third parties do not renew or extend their contracts with QEP or if third parties suspend or terminate their contracts with QEP, the Company's financial results would suffer.

QEP is dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies. If QEP is unable to obtain needed capital or financing on satisfactory terms, QEP may experience a decline in its natural gas and oil production rates and reserves. QEP is partially dependent on external capital sources to provide financing for certain projects. The availability and cost of these capital sources is cyclical, and these capital sources may not remain available, or the Company may not be able to obtain financing at a reasonable cost in the future. Over the last few years, conditions in the global capital markets have deteriorated, making terms for certain financings less attractive, and in certain cases, resulting in the unavailability of certain types of financing. If QEP's revenues decline as a result of lower natural gas, oil and NGL prices, operating difficulties, declines in production or for any other reason, QEP may have limited ability to obtain the capital necessary to sustain its operations at current levels. The Company utilizes its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. All of QEP's debt under its revolving credit facility is floating-rate debt. From time to time, the Company may use interest-rate derivatives to fix the interest rate on a portion of its floating-rate debt. The interest rates on debt under the Company's revolving credit facility are tied to QEP's ratio of indebtedness to Consolidated EBITDAX (as defined in the credit agreement.)

QEP relies on access to capital markets to meet long-term funding needs. A downgrade of credit ratings may make it more difficult or expensive to raise capital from financial institutions or other sources. QEP's failure to obtain additional financing could result in a curtailment of its operations relating to exploration and development of its prospects, which in turn could lead to a possible reduction in QEP's natural gas or oil production, reserves and its revenues, and could negatively impact its results of operations.

QEP is exposed to counterparty credit risk as a result of QEP's receivables and commodity derivative transactions. QEP has significant credit exposure to outstanding accounts receivable from joint interest and working interest owners as well as customers in all segments of its business. Because QEP is the operator of a majority of its production and major development projects, QEP pays joint venture expenses and in some cases makes cash calls on its non-operating partners for their respective shares of joint venture costs. These projects are capital intensive and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs. Counterparty liquidity problems could result in a delay in QEP receiving proceeds from commodity sales or reimbursement of joint venture costs. Credit enhancements, such as financial guarantees or prepayments, have been obtained from some but not all parties. Nonperformance by a trade creditor or joint venture partner could result in financial losses. In addition, QEP's commodity derivative transactions expose it to risk of financial loss if the counterparty fails to perform under a contract. During periods of falling commodity prices, QEP's commodity derivative receivable positions increase, which increases its counterparty credit exposure.

QEP faces various risks associated with the trend toward increased activism against oil and gas exploration and development activities. Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry, such as QEP, are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, amongst other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, environmental activists have recently advocated for increased regulations on shale drilling in the U.S. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- increased severance and/or other taxes;
- legal challenges or lawsuits;
- damaging publicity about QEP;
- increased costs of doing business;
- reduction in demand for QEP's products; and
- other adverse affects on QEP's ability to develop its properties and expand production.

QEP's need to incur costs associated with responding to these initiatives or complying with any resulting additional legal or regulatory requirements that are substantial and not adequately provided for could have a material adverse effect on its business, financial condition and results of operations.

Risks Related to Strategy

QEP's use of derivative instruments to manage exposure to uncertain prices could result in financial losses or reduce its income. QEP uses commodity-price derivative arrangements to reduce exposure to the volatility of natural gas, oil, and NGL prices and to protect cash flow, returns on capital, net income and credit ratings from downward commodity price movements. To the extent the Company enters into commodity derivative transactions, it may forgo some or all of the benefits of commodity price increases. Additionally, there are proposed financial regulations which may change QEP's reporting and margining requirements relating to such instruments. Furthermore, QEP's use of derivative instruments through which it attempts to reduce the economic risk of its participation in commodity markets could result in increased volatility of QEP's reported results. Changes in the fair values (gains and losses) of derivatives that have not been designated as cash flow hedges must be recorded into QEP's income. This creates the risk of volatility in earnings even if no economic impact to QEP has occurred during the applicable period.

QEP enters into commodity-price derivative arrangements with creditworthy counterparties (banks and energy-trading firms) that do not require collateral deposits. QEP is exposed to the risk of counterparties not performing. The amount of credit available may vary depending on our counterparties assessment of QEP's credit risk.

Relative changes in NGL product and natural gas prices may adversely impact QEP's results due to frac spread, natural gas and liquids exposure. Approximately 30% and 22% of QEP Field Services' net operating revenues for 2011 and 2010, respectively, were derived from keep-whole processing agreements. Under QEP's keep-whole arrangements, QEP's principal cost is delivering dry gas of an equivalent Btu content to replace Btus extracted from the gas stream in the form of NGLs, or consumed as fuel during processing. The spread between the NGL product sales price and the purchase price of natural gas with an equivalent Btu content is called the "frac spread." Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event natural gas becomes more expensive on a Btu equivalent basis than NGL products, QEP's cost of keeping the producer "whole" results in operating losses. Due to timing of gas purchases and liquid sales, direct exposure to changes in market prices of either gas or liquids can be created, because there is an offsetting purchase or sale that remains exposed to market pricing. Through QEP's marketing and derivatives activity, direct exposure may occur naturally or QEP may choose direct price exposure to either gas or liquids when QEP favors that exposure over frac spread risk. Given that QEP has derivative positions, adverse movement in prices to the positions QEP has taken will negatively impact results.

QEP has made significant investments in new cryogenic gas processing plants in its Northern Region (Rockies) in recent years. The expected returns on these investments depend in large part on the future price of ethane and ethane margins, which historically have been more volatile than the price of propane and butane. QEP competitors have also made significant investments in gas processing plants that recover significant volumes of ethane. The U.S. ethane market may, and probably will, become oversupplied from time to time in the future, resulting in lower ethane prices.

QEP's plans to grow its midstream business by constructing new processing and treating facilities subjects the Company to construction risks and the risk that the Company will not be able to secure long-term contracts from third parties required to earn acceptable returns on these investments. One of the ways QEP has grown its business is through the construction of new gathering, treating and processing facilities. The construction of gathering, treating and processing facilities requires the expenditure of significant amounts of capital and involves numerous regulatory, environmental, political, legal and inflationary uncertainties. If QEP undertakes these projects, QEP may not be able to complete them on schedule, or at all, or at the budgeted cost. While QEP may commit natural gas supplies from its production, such supplies many not be sufficient to fill available capacity at these facilities, leaving QEP with limited natural gas supplies committed to these facilities prior to and after their construction. Moreover, QEP may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. QEP may also rely on estimates of proved reserves in its decision to construct new facilities, which may prove to be inaccurate, because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to process or treat enough natural gas to achieve QEP's expected investment return, which could adversely affect QEP's operations and cash flows.

QEP faces significant competition and certain of its competitors have resources in excess of QEP's available resources. QEP operates in the highly competitive areas of natural gas and oil exploration, exploitation, acquisition and production. QEP faces competition from:

- large multi-national, integrated oil companies;
- US independent oil and gas companies;
- service companies engaging in oil and gas exploration and production activities; and
- private oil and gas equity funds.

QEP faces competition in a number of areas such as:

- acquiring desirable producing properties or new leases for future exploration;
- marketing its natural gas, oil and NGL production;
- obtaining the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain skills.

Certain of QEP's competitors have financial and other resources in excess of those available to QEP. Such companies may be able to pay more for seismic and lease rights on natural gas and oil properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than QEP's financial or human resources permit. This highly competitive environment could have an adverse impact on QEP's business.

QEP may be subject to risks in connection with acquisitions and organizational changes. The acquisition of gas and oil properties requires the assessment of recoverable reserves, future gas and oil sales prices and basis differentials, operating costs,and potential environmental and other liabilities. The accuracy of these assessments is inherently uncertain. QEP may not be able to identify attractive acquisition opportunities. Even if QEP does identify attractive opportunities, it may not be able to complete the acquisitions due to capital constraints. If QEP acquires an additional business, QEP could have difficulty integrating the operations, systems, management and other personnel and technology of the acquired business with QEP's own, or could assume unidentified or unforeseeable liabilities, resulting in a loss of value.

Organizational modifications due to acquisitions, divestitures or other strategic changes can alter the risk and control environments, disrupt ongoing business, distract management and employees, increase expenses and adversely affect results of operations. Even if these challenges can be dealt with successfully, the anticipated benefits of any acquisition, divestiture or other strategic change may not be realized.

Failure of the Company's controls and procedures to detect error or fraud could seriously harm its business and results of operations. QEP's management, including its Chief Executive Officer and Chief Financial Officer, does not expect that the Company's internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of QEP's controls can provide absolute assurance that all control issues and instances of fraud, if any, in the Company have been detected. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection.

Risks Related to Regulation

QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves. QEP's operations are subject to extensive regulation. The failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. Due to the myriad of complex federal, state, tribal and local regulations that may affect the Company, directly or indirectly, the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting its operations.

The Company is subject to extensive federal, state, tribal and local tax, environmental, health and safety laws and regulations. Environmental laws and regulations are complex, change frequently and tend to become more onerous over time. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, or injunctions that could threaten QEP's authorization to operate.

QEP must comply with numerous and complex federal and state regulations governing activities on federal, state and tribal lands, notably the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, and the National Historic Preservation Act and similar state laws. Federal and state regulatory agencies frequently impose conditions on the Company's activities. These restrictions have become more stringent over time and can limit or prevent exploration and production on the Company's leasehold. Certain environmental groups oppose drilling on some of QEP's federal and state leases. These groups sometimes sue federal and state regulatory agencies for alleged procedural violations in an attempt to stop, limit or delay natural gas and oil development on public lands.

The United States Fish and Wildlife Service may designate critical habitat areas for certain listed threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. The listing of certain species, such as the sage grouse, as threatened and endangered, could have a material impact on the Company's operations in areas where such species are found.

The Clean Water Act and similar state laws regulate discharges of stormwater, wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and other costs and damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Land Management and the Bureau of Indian Affairs, along with potentially each Native American tribe, promulgate and enforce regulations pertaining to natural gas and oil operations on Native American tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, under prevailing legal precedent each Native American tribe has limited attributes of sovereignty including the right to enforce laws and regulations independent from federal, state and local statutes and regulations so long as not inconsistent with federal law and regulation. 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 may be subject to the Native American tribal court system. One or more of these factors may increase the Company's costs of doing business on Native American tribal lands and have an impact on the viability of its gas and oil exploration, production, gathering, processing and transportation operations on such lands.

FERC regulates interstate natural gas transportation (including storage). QEP owns three facilities that are directly regulated by FERC as either an interstate pipeline or a natural gas storage facility connected to interstate pipelines. Since the enactment of the Energy Policy Act of 2005, granting FERC increased penalty authority for non compliance, FERC has targeted various issues in the natural gas industry for compliance audits and investigations.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. These statutes are administered by FERC. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by QEP of its own production. All other sales of natural gas by QEP, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of QEP's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. QEP's jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of oil and condensate and NGL by QEP are made at unregulated market prices.

QEP may not be able to obtain the permits and approvals necessary to continue and expand its operations. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of the Company's exploration and production and midstream field services operations. Further, the public may comment on and otherwise seek to influence the permitting process, including through intervention in the courts. Accordingly, needed permits may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict QEP's ability to conduct its operations or to do so profitably.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation. On September 12, 2011, President Obama sent a legislative package to Congress that included proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes included (i) the repeal of the percentage depletion allowance for oil and natural gas wells, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. President Obama's Proposed Fiscal Year 2012 Budget includes the foregoing proposals in substantially similar form. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development and increase the cost of exploration and development of natural gas and oil resources. Any such changes could have an adverse effect on QEP's financial position, results of operations and cash flows.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to natural gas and oil reserves. All wells drilled in tight sand and shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. The majority of the Company's current and future production and oil and gas reserves are derived from reservoirs that require hydraulic fracture stimulation to be commercially viable. Hydraulic fracture stimulation involves pumping fluid at high pressure into tight sand or shale reservoirs to artificially induce fractures. The artificially induced fractures allow better connection between the wellbore and the surrounding reservoir rock, thereby enhancing the productive capacity and ultimate hydrocarbon recovery of each well. The fracture stimulation fluid is typically comprised of over 99 percent water and sand, with the remaining constituents consisting of additives designed to optimize the fracture stimulation treatment and production from the reservoir. The Company does not use diesel fuel in any of its fracturing operations. QEP obtains water for fracture stimulations from a variety of sources including industrial water wells and surface sources. When technically and economically feasible, the Company recycles flow-back and produced water, which reduces water consumption from surface and groundwater sources and reduces produced water disposal volumes. The Company believes that the employment of fracture stimulation technology does not present any significant additional risks other than the risks generally associated with natural gas and oil drilling and production operations described above, such as the risk of spills, releases, discharges, accidents and injuries to persons and property.

Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of natural gas and oil well design and operation. The Company supports disclosure of the contents of hydraulic fracturing fluids, and submits information regarding its wells to the national online disclosure registry, FracFocus (www.fracfocus.org). The EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. In the event that new or more stringent federal, state or local legal restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or stimulating wells in some areas.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a wastewater treatment plant. In addition, the U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling employing hydraulic fracture stimulation. Also, the U.S.

Department of the Interior has indicated it intends to issue new regulations regarding disclosure requirements and other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the U.S. Securities & Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

QEP's ability to produce natural gas and oil economically and in commercial quantities could be impaired if it is unable to acquire adequate supplies of water for its drilling operations or is unable to dispose of or recycle the water it uses at a reasonable cost and in accordance with applicable environmental rules. The hydraulic fracturing process on which QEP depends to produce commercial quantities of natural gas and oil requires the use and disposal of significant quantities of water. QEP's inability to secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact its operations in these regions. As noted above, the imposition of new environmental initiatives and regulations could include restrictions on QEP's 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. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase QEP's operating costs and cause delays, interruptions or termination of its operations, the extent of which cannot be predicted, and all of which could have an adverse effect on QEP's operations and financial condition.

The adoption of greenhouse gas (GHG) emission or other environmental legislation could result in increased operating costs, delays in obtaining air pollution permits for new or modified facilities, and reduced demand for the natural gas, oil and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of climate-change regulation under various laws pertaining to the environment, energy use and development, and GHG emissions. QEP's ability to access and develop new natural gas reserves may be restricted by climate-change regulation. In legislative sessions bills have been pending in Congress that would regulate GHG emissions through a cap-and-trade system under which emitters would be required to buy allowances for offsets of emissions of GHG. The Environmental Protection Agency (EPA) has adopted final regulations for the measurement and reporting of GHG emitted from certain large facilities (25,000 tons/year of carbon dioxide (CO_2) equivalent) beginning with operations in 2010. The first such reports were filed with the EPA prior to March 31, 2011. Additionally, the EPA and authorized states have begun the permitting of major sources of GHG under the Clean Air Act pursuant to the EPA's GHG Tailoring Rule whereby new and existing sources of GHG emitting above major source thresholds (100,000 metric tons per year of CO_2 equivalent emissions) will be required to obtain major source permits. In addition, several of the states in which QEP operates are considering various GHG registration and reduction programs. Carbon dioxide and other GHG regulation could increase the price of natural gas, restrict access to or the use of natural gas, and/or reduce natural gas demand. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for natural gas. While future climate-change regulation is possible at the federal level, it is too early to predict how such regulation would affect QEP's business, operations or financial results. It is uncertain whether QEP's operations and properties, located in the Northern and Southern Regions of the United States, are exposed to possible physical risks, such as severe weather patterns, due to climate change that may or may not be the result of anthropogenic emissions of GHG. Management does not, however, believe such physical risks are reasonably likely to have a material effect on the Company's financial condition or results of operations.

Derivatives regulation could increase QEP's liquidity risks by restricting its use of derivative instruments. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain derivative transactions be cleared on exchanges, a requirement to post cash collateral (commonly referred to as "margin") for such derivative transactions, and strong business conduct standards. The Dodd-Frank Act exempts non-financial end-users using derivatives to hedge business risk from the central clearing requirements of the Dodd-Frank Act. The availability of the "end-user exemption" to exempt commercial end-users from the act's margin requirements depends on rules not yet finalized by the Commodities Futures and Trading Commission (CFTC). In January 2012, the CFTC released an updated timeline indicating that the CFTC would finalize these rules in the first quarter of 2012.

If an end-user exemption from the Dodd-Frank Act's margin requirements is not available to QEP, the Company could be required to post significant amounts of cash collateral with its dealer counterparties for its derivative transactions. A sudden, unexpected margin call triggered by rising commodity prices would have an immediate negative impact on QEP's liquidity, forcing QEP to divert capital from exploration, development and production activities. Requirements to post cash collateral could not only cause significant liquidity issues by reducing the Company's flexibility in using its cash and other sources of funds, such as its revolving credit facility, but could also cause QEP to incur additional debt. In addition, a requirement for QEP's counterparties to post cash collateral would likely result in additional costs being passed on to QEP, thereby decreasing the effectiveness of its commodity derivatives and its profitability. If the costs of complying with the clearing and margin requirements and business conduct rules under the Dodd-Frank

Act significantly increase the costs of entering into commodity derivative transactions, QEP may reduce its commodity derivative program, which could increase its exposure to fluctuating commodity prices, increase the volatility of QEP's results of operations and reduce the predictability of the Company's cash flows, which in turn could adversely affect QEP's ability to plan for and fund capital expenditures.

Other Risks

General economic and other conditions impact QEP's results. QEP's results may also be negatively affected by: changes in global economic conditions; changes in regulation; availability and economic viability of gas and oil properties for sale or exploration; creditworthiness of counterparties; rate of inflation and interest rates; assumptions used in business combinations; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy, other pipelines and storage facilities; effects of accounting policies issued periodically by accounting standard-setting bodies; terrorist attacks or acts of war; changes in business or financial condition; changes in credit ratings; and availability of financing for QEP.

The Company's pension plans are currently underfunded and may require large contributions, which may divert funds from other uses. Approximately 190 of QEP's employees participate in the closed defined benefit pension plan (QEP Resources, Inc. Retirement Plan). Over time, periods of declines in interest rates and pension asset values may result in a reduction in the funded status of the Company's pension plans. As of December 31, 2011 and 2010, QEP's pension plans were \$59.9 million and \$47.1 million underfunded. The underfunded status of QEP's pension plans may require that the Company make large contributions to such plans. QEP made cash contributions of \$14.8 million and \$1.6 million in 2011 and 2010, respectively, to its defined benefit pension plans and expect to make contributions of approximately \$6.3 million to the funded plan in 2012. QEP cannot, however, predict whether changing economic conditions, the future performance of assets in the plans or other factors will require the Company to make contributions in excess of its current expectations, diverting funds QEP would otherwise apply to other uses.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

EXPLORATION AND PRODUCTION

QEP's exploration and production business is conducted through QEP Energy in two core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, New Mexico and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana).

Southern Region

Haynesville/Cotton Valley

QEP Energy has approximately 50,800 net acres of Haynesville Shale lease rights in northwest Louisiana and additional lease rights that cover the Hosston and Cotton Valley formations. The depth of the top of the Haynesville Shale ranges from approximately 10,500 feet to 12,500 feet across QEP Energy's leasehold and is below the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana for over a decade. As of December 31, 2011, QEP Energy had three operated rigs drilling in the project area.

Midcontinent

QEP Energy's Midcontinent properties cover all properties in the Southern Region except the Haynesville/Cotton Valley area of northwest Louisiana and are distributed over a large area, including the Anadarko Basin of Oklahoma and the Texas Panhandle.

QEP Energy has approximately 77,000 net acres of Woodford Shale lease rights in western Oklahoma. The true vertical depth to the top of the Woodford Shale ranges from approximately 10,500 feet to 14,500 feet across QEP Energy's leasehold. As of December 31, 2011, QEP Energy had two operated rigs drilling in the project.

QEP Energy has approximately 38,700 net acres of Granite Wash/Atoka Wash lease rights in the Texas Panhandle and western Oklahoma and has been drilling vertical Granite Wash/Atoka Wash wells for over a decade. The true vertical depth to the top of the Granite Wash/Atoka Wash interval ranges from approximately 11,100 feet to 15,900 feet across QEP Energy's leasehold. In the past few years, QEP and other operators have drilled a number of successful horizontal wells in the Granite Wash/Atoka Wash play but have also drilled some wells with disappointing results. As of December 31, 2011, QEP Energy did not have any rigs drilling in the Granite Wash/Atoka Wash. In addition to its operated drilling programs, QEP Energy receives and participates in a large number of outside-operated well proposals.

Northern Region

Pinedale Anticline

In 2005, the Wyoming Oil and Gas Conservation Commission (WOGCC) approved 10 acre density drilling for Lance Pool wells on about 12,700 acres of QEP Energy's 17,872 acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the currently estimated productive limits of QEP Energy core acreage in the field. In January 2008, the WOGCC approved five-acre density drilling for Lance Pool wells on about 4,200 gross acres of QEP Energy's Pinedale leasehold. The true vertical depth to the top of the Lance Pool tight gas sand reservoir interval ranges from 8,500 to 9,500 feet across QEP Energy's acreage. The Company currently estimates that up to 1,100 additional wells will be required to fully develop its Pinedale acreage on a combination of 5 and 10-acre density. In addition to QEP Energy's gross producing wells, QEP Energy had an overriding royalty interest only in an additional 21 wells at Pinedale.

Uinta Basin

The majority of Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 5,000 feet to deeper than 18,000 feet. QEP Energy owns interests in approximately 255,200 net leasehold acres in the Uinta Basin.

Rockies Legacy

The remainder of QEP Energy Northern Region leasehold interests, productive wells and proved reserves are distributed over a number of fields and properties managed as the Rockies Legacy division. Exploration and development activity in 2011 includes wells in the Powder River and Greater Green River Basins in Wyoming and the Williston Basin in North Dakota.

QEP Energy has approximately 90,000 net acres of lease rights in the Williston Basin in western North Dakota, where the company is targeting the Bakken and Three Forks formations. The true vertical depth to the top of the Bakken Formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. The Three Forks Formation lies approximately 60 to 70 feet below the Middle Bakken Formation and is also a target for horizontal drilling. As of December 31, 2011, QEP Energy had one operated rig drilling in the project area.

Reserves – QEP Energy

At December 31, 2011 and 2010, approximately 91% and 88% of QEP Energy's estimated proved reserves were Company operated. Proved developed reserves represented 54% and 53% of the Company's total proved reserves at December 31, 2011 and 2010, respectively, while the remaining 46% and 47% of reserves were classified as proved undeveloped at December 31, 2011 and 2010. All reported reserves are located in the United States. QEP Energy does not have any long-term supply contracts with foreign governments, reserves of equity investees or reserves of subsidiaries with a significant minority interest. QEP Energy's estimated reserves are summarized as follows:

	December 31, 2011				December 31, 2010			
	Natural Gas	Oil	NGL	Natural Gas Equivalents [1]	Natural Gas	Oil	NGL	Natural Gas Equivalents [1]
	(Bcf)	(Mbbl)	(Mbbl)	(Bcfe)	(Bcf)	(Mbbl)	(Mbbl)	(Bcfe)
Proved developed reserves	1,538.3	32,955.5	38,388.1	1,966.3	1,404.8	25,115.6	9,342.9	1,611.5
Proved undeveloped reserves	1,211.1	34,559.3	38,169.0	1,647.5	1,208.1	27,161.1	8,026.6	1,419.2
Total proved reserves	2,749.4	67,514.8	76,557.1	3,613.8	2,612.9	52,276.7	17,369.5	3,030.7

[1] Oil and NGLs are converted to natural gas equivalents at the ratio of one bbl of oil or NGL to six Mcf of equivalent natural gas.

QEP Energy's reserve statistics for the years ended December 31, 2009 through 2011, are summarized below:

Year ended December 31,	Year End Resrves (Bcfe)	Natural Gas, Oil and NGL Production (Bcfe)	Reseve Life Index [1] (Years)
2009	2,746.9	189.5	14.5
2010	3,030.7	229.0	13.2
2011	**3,613.8**	**275.2**	**13.1**

[1] Reserve life index is calculated by dividing year-end proved reserves by production for such year.

Proved Reserves

Reserve and related information for 2011 and 2010 is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting, that we adopted December 31, 2009. These revised rules expand the use of reliable technologies to estimate and categorize reserves and require the use of the average of the first-of-the-month prices for the prior 12 months (unless contractual arrangements designate the price) to be used to calculate economic producibility of reserves and the discounted cash flows reported as the Standardized Measure of Future Net Cash Flows Relating to Proved Reserves. Refer to Note 14 of the consolidated financial statements included in Item 8 of Part II of this Annual Report for additional information regarding estimates of proved reserves and the preparation of such estimates.

QEP Energy's proved reserves in major operating areas at December 31, 2011 and 2010 are summarized below:

	2011		2010	
	(Bcfe)	(% of total)	(Bcfe)	(% of total)
Southern Region				
Haynesville/Cotton Valley	**782.9**	**22**	728.3	24
Midcontinent	**518.7**	**14**	442.2	15
Northern Region				
Pinedale Anticline	**1,531.0**	**42**	1,348.9	44
Uinta Basin	**393.6**	**11**	212.8	7
Rockies Legacy	**387.6**	**11**	298.5	10
Total QEP Energy	**3,613.8**	**100**	3,030.7	100

Estimates of the quantity of proved reserves from the Company's Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling activity, producing well performance and the development and application of reliable technologies. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes. With the application of the amendments of ASC 932 in ASU 2010-03, reserves associated with Pinedale increased density drilling are included in extensions and discoveries for the years ended December 31, 2011, 2010 and 2009, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

Proved Undeveloped Reserves

Significant changes to proved undeveloped reserves (PUDs) occurring during 2011 are summarized in the table below:

	2011
	(Bcfe)
Proved undeveloped reserves at January 1,	1,419.2
Transferred to proved developed reserves	(314.5)
Revisions to previous estimates	(37.2)
Extensions and discoveries	580.0
Proved undeveloped reserves at December 31, [1]	**1,647.5**

(1) All of QEP Energy's proved undeveloped reserves at December 31, 2011, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 217 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural gas reserves in Pinedale is governed by the BLM's September 2008, ROD on the FSEIS. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas. The ROD contains additional requirements and restrictions on the sequence of development, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development that is beyond the control of the Company. The Company has an ongoing development plan and the financial capability to continue development in the manner estimated.

The costs incurred to continue the development of proved undeveloped reserves were approximately \$533.6 million, \$434.2 million and \$216.1 million for the years ended December 31 2011, 2010 and 2009, respectively. The costs incurred in 2011 related to the drilling of PUDs in QEP development projects, which are discussed in Item 2 above. This investment resulted in the transfer in 2011 of 314.5 Bcfe of reserves from proved undeveloped to proved developed, representing 22% of the total proved undeveloped reserves that were recorded at December 31, 2010.

Estimated future development costs relating to the development of PUDs are projected to be approximately \$614.9 million in 2012, \$788.8 million in 2013 and \$757.7 million in 2014. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. Proved undeveloped reserves related to major development projects will be reclassified to proved developed reserves when production commences.

Internal Controls Over Reserve Estimates, Technical Qualifications and Technologies Used

Estimates of proved gas and oil reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which includes the compliance oversight of a multi-functional reserves review committee responsible to the Company's board of directors. We retained Ryder Scott Company, independent oil and gas reserve evaluation engineering consultants ("Ryder Scott"), to prepare the estimates of 100% of our reserves as of December 31, 2011, 2010 and 2009. The individual at Ryder Scott who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2011, is a registered Professional Engineer in the State of Colorado and graduated with a Bachelors of Science degree in Geology from the University of Missouri at Rolla in 1976. The individual has over thirty years experience in the Petroleum Industry, including experience estimating and evaluating petroleum reserves. A more detailed letter of the individual's professional qualifications has been filed as part of Exhibit 23.2 to this report.

The individual at QEP Resources responsible for insuring the accuracy of the reserve estimate preparation material provided to Ryder Scott and reviewing the estimates of reserves received from Ryder Scott was our Chief Reservoir Engineer. Such individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Petroleum Engineering from Mississippi State University in 1993. This individual has 17 years experience in the Petroleum Industry, including 13 years reservoir engineering experience in most of the active domestic basins in the United States. A more detailed letter of the individual's professional qualifications has been filed as part of Exhibit 23.2 to this report.

The SEC's new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. A variety of methodologies were used to determine our proved reserve estimates. The principal methodologies employed are performance, analogy or volumetric methods. All of the proved producing reserves attributable to producing wells and reservoirs were estimated by performance methods. Performance methods include, but may not be limited to, decline curve analysis which utilizes extrapolations of historical production and pressure data. Approximately 99 percent of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K were estimated by analogy and the remaining approximately one percent of the proved developed non-producing and undeveloped reserves were estimated by the volumetric method. Some combination of these methods is used to determine reserve estimates in substantially all of QEP's fields.

Refer to Note 14 of the consolidated financial statements included in Item 8 of Part II of this Annual Report for additional information pertaining to QEP Energy's proved reserves as of the end of each of the last three years. In addition to this filing, QEP Energy will file reserves estimates as of December 31, 2011, with the Energy Information Administration of the Department of Energy on Form EIA-23. Although QEP uses the same technical and economic assumptions when it prepares the EIA-23 as used to estimate reserves for this Annual Report on Form 10-K, it is obligated to report reserves for only wells it operates, not for all of the wells in which it has an interest, and to include the reserves attributable to other owners in such wells.

Production, Production Prices and Production Costs

The following table sets forth the net production volumes, the average net realized prices per Mcf of natural gas, per bbl of oil and per bbl of NGL produced, and the operating expenses per Mcfe for the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
QEP Energy			
Volumes produced and sold			
Natural gas (Bcf)	**236.4**	203.8	168.7
Oil (Mbbl)	**3,741.3**	2,979.8	2,746.7
NGL (Mbbl)	**2,715.6**	1,225.8	705.0
Total production (Bcfe)	**275.2**	229.0	189.5
Average field-level price (1)			
Natural gas (per Mcf)	**$ 3.95**	$ 4.18	$ 3.48
Oil (per bbl)	**86.20**	69.39	50.88
NGL (per bbl)	**47.76**	39.04	31.82
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.54**	$ 0.56	$ 0.67
Production taxes	**0.36**	0.34	0.31
Total lifting costs	**$ 0.90**	$ 0.90	$ 0.98

(1) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, were recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. This change had no impact on net income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

(2) The average field-level price does not include the impact of settled commodity price derivatives.

A summary of natural gas production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Natural gas (Bcf)					
Southern Region					
Haynesville/Cotton Valley	**107.1**	79.3	46.9	**27.8**	32.4
Midcontinent	**32.9**	30.8	32.7	**2.1**	(1.9)
Northern Region					
Pinedale Anticline	**69.3**	65.1	58.9	**4.2**	6.2
Uinta Basin	**14.9**	14.9	16.7	**-**	(1.8)
Rockies Legacy	**12.2**	13.7	13.5	**(1.5)**	0.2
Total production	**236.4**	203.8	168.7	**32.6**	35.1

A summary of oil production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Oil (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**51.0**	78.4	121.1	**(27.4)**	(42.7)
Midcontinent	**835.3**	644.3	775.1	**191.0**	(130.8)
Northern Region					
Pinedale Anticline	**583.8**	551.8	486.9	**32.0**	64.9
Uinta Basin	**866.7**	957.1	930.7	**(90.4)**	26.4
Rockies Legacy	**1,404.5**	748.2	432.9	**656.3**	315.3
Total production	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1

A summary of NGL production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - NGL (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**8.4**	5.5	3.3	**2.9**	2.2
Midcontinent	**1,371.2**	997.0	456.1	**374.2**	540.9
Northern Region					
Pinedale Anticline	**1,099.6**	-	-	**1,099.6**	-
Uinta Basin	**106.4**	121.5	151.2	**(15.1)**	(29.7)
Rockies Legacy	**130.0**	101.8	94.4	**28.2**	7.4
Total production	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8

A summary of natural gas equivalent total production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Total Production (Bcfe)					
Southern Region					
Haynesville/Cotton Valley	**107.5**	79.8	47.7	**27.7**	32.1
Midcontinent	**46.2**	40.6	40.1	**5.6**	0.5
Northern Region					
Pinedale Anticline	**79.4**	68.5	61.8	**10.9**	6.7
Uinta Basin	**20.8**	21.4	23.2	**(0.6)**	(1.8)
Rockies Legacy	**21.3**	18.7	16.7	**2.6**	2.0
Total production	**275.2**	229.0	189.5	**46.2**	39.5

Productive Wells

The following table summarizes the Company's productive wells as of December 31, 2011. All of our wells are located in the United States.

	Natural gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Southern Region						
Haynesville/Cotton Valley	1,413	669	7	4	1,420	673
Midcontinent	1,757	544	378	84	2,135	628
Northern Region						
Pinedale Anticline	613	377	-	-	613	377
Uinta Basin	660	469	1,651	194	2,311	663
Rockies Legacy	780	272	431	161	1,211	433
Total productive wells	5,223	2,331	2,467	443	7,690	2,774

The term "gross" refers to all wells or acreage in which QEP has at least a partial working interest and the term "net" refers to QEP's ownership represented by that working interest. Although many wells produce both natural gas and oil, and many natural gas wells also have allocated NGL volumes from processing, a well is categorized as either a natural gas or an oil well based upon the ratio of gas to oil produced at the wellhead. Each gross well completed in more than one producing zone is counted as a single well. At the end of 2011, the Company had 90 gross wells with completions in more than one reservoir.

The Company also holds numerous overriding royalty interests in gas and oil wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these wells with overriding royalty interests will be included in the gross and net-well count.

Leasehold Acreage

The following table summarizes developed and undeveloped leasehold acreage in which the Company owns a working interest or mineral interest as of December 31, 2011. "Undeveloped Acreage" includes leasehold interests that already may have been classified as containing proved undeveloped reserves and unleased mineral interest acreage owned by the Company. Excluded from the table is acreage in which the Company's interest is limited to royalty, overriding royalty and other similar interests. All leasehold acres are located in the United States.

	Developed Acres (1)		Undeveloped Acres (2)		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	33,733	9,837	5,369	3,362	39,102	13,199
Colorado	155,897	105,737	111,062	33,389	266,959	139,126
Kansas	28,994	12,894	52,379	17,205	81,373	30,099
Louisiana	72,351	60,036	6,483	6,064	78,834	66,100
Montana	14,294	7,637	306,619	52,843	320,913	60,480
New Mexico	99,802	71,859	32,619	12,600	132,421	84,459
North Dakota	38,033	10,804	212,652	88,756	250,685	99,560
Oklahoma	655,124	275,690	489,406	150,279	1,144,530	425,969
South Dakota	-	-	204,398	107,151	204,398	107,151
Texas	133,602	46,593	51,927	49,206	185,529	95,799
Utah	167,052	134,208	235,542	152,897	402,594	287,105
Wyoming	265,196	158,043	388,755	276,866	653,951	434,909
Other	2,429	735	158,475	43,357	160,904	44,092
Total	1,666,507	894,073	2,255,686	993,975	3,922,193	1,888,048

(1) Developed acreage is acreage assigned to productive wells.

(2) Undeveloped acreage is leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

A portion of the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed or production has been established from the acreage subject to the lease prior to that date. Leases held by production remain in effect until production ceases. The following table sets forth the gross and net acres subject to leases summarized in the preceding table that will expire during the periods indicated:

Leaseholds Expiring

	Undeveloped Acres Expiring	
	Gross	Net
12 months ending December 31,		
2012	56,351	36,718
2013	130,548	73,981
2014	67,140	47,618
2015	92,182	73,661
2016 and later	152,370	145,321

Drilling Activity

The following table summarizes the number of development and exploratory wells drilled on acreage owned by QEP during the years indicated.

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2011								
Southern Region								
Haynesville/Cotton Valley	**91.0**	**36.7**	**-**	**-**	**6.0**	**1.7**	**2.0**	**0.7**
Midcontinent	**221.0**	**39.6**	**-**	**-**	**-**	**-**	**4.0**	**1.9**
Northern Region								
Pinedale	**105.0**	**71.6**	**-**	**-**	**-**	**-**	**-**	**-**
Uinta Basin	**176.0**	**6.3**	**-**	**-**	**-**	**-**	**-**	**-**
Rockies Legacy	**85.0**	**22.5**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**678.0**	**176.7**	**-**	**-**	**6.0**	**1.7**	**6.0**	**2.6**
Year Ended December 31, 2010								
Southern Region								
Haynesville/Cotton Valley	85.0	44.0	-	-	33.0	16.2	1.0	1.0
Midcontinent	98.0	22.4	-	-	-	-	-	-
Northern Region								
Pinedale	103.0	72.5	-	-	-	-	-	-
Uinta Basin	188.0	23.9	-	-	-	-	-	-
Rockies Legacy	42.0	7.7	-	-	-	-	1.0	0.9
Total	516.0	170.5	-	-	33.0	16.2	2.0	1.9
Year Ended December 31, 2009								
Southern Region								
Haynesville/Cotton Valley	82.0	61.6	-	-	8.0	1.8	-	-
Midcontinent	76.0	24.8	-	-	-	-	-	-
Northern Region								
Pinedale	96.0	58.6	-	-	-	-	-	-
Uinta Basin	7.0	6.7	-	-	-	-	-	-
Rockies Legacy	12.0	2.8	1.0	-	4.0	1.9	-	-
Total	273.0	154.5	1.0	-	12.0	3.7	-	-

The following table presents operated and non-operated well activity at December 31, 2011 as well as completions for the year ended December 31, 2011:

	Operated						Non-operated					
	Completions		Drilling		Waiting on completion		Completions		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southern Region												
Haynesville/Cotton Valley	38.0	30.3	8.0	6.9	21.0	10.6	59.0	8.1	-	-	4.0	0.3
Midcontinent	29.0	21.8	2.0	1.3	4.0	2.4	192.0	17.8	13.0	1.7	11.0	2.1
Northern Region												-
Pinedale	105.0	71.6	4.0	2.4	24.0	17.3	-	-	-	-	-	-
Uinta Basin	7.0	5.9	1.0	1.0	2.0	2.0	169.0	0.4	2.0	0.1	-	-
Rockies Legacy	23.0	20.1	-	-	4.0	3.7	62.0	2.4	13.0	0.4	20.0	4.2

Delivery Commitments

The Company sells NGLs under a term sales agreement that contains a delivery commitment for 8,500 barrels per day of NGL derived from several of QEP Field Services' gas processing facilities in the Northern Region. The agreement, which was effective May 1, 2010, extends for a period of seven years and contains terms and conditions customary for an agreement of this type in the oil and gas industry. The Company believes that the reserves dedicated to its gas processing facilities and projected processing volumes are adequate to satisfy its delivery commitments under this agreement.

The Company is a party to various long-term sales commitments for physical delivery of natural gas with future firm delivery commitments as follows:

Period	Delivery Commitments (millions of MMBtu)
2012	**186.7**
2013	**75.8**
2014	**28.9**
2015	**18.8**
2016	**-**
After 2016	**-**

These commitments are physical delivery obligations with prices related to the prevailing index prices for natural gas at the time of delivery. None of these commitments require the Company to deliver natural gas produced specifically from any of the Company's properties. The Company believes that its production and reserves are adequate to meet these term sales commitments. If for some reason the Company's natural gas production is not sufficient to satisfy its term sales commitments, the Company believes it can purchase sufficient volumes of natural gas in the market at index-related prices to satisfy its commitments.

In addition, none of the Company's production from QEP Energy owned properties is subject to any priorities, proration or third-party imposed curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in "Risk Factors" in this Annual Report on Form 10-K.

MIDSTREAM FIELD SERVICES – QEP Field Services

QEP Field Services owns 1,905 miles of gathering lines in Utah, Wyoming, Colorado, Louisiana and North Dakota. At December 31, 2011 QEP Field Services also owns processing plants, which remove NGL from the natural gas stream, that have an aggregate processing capacity, of 1.37 Bcf per day of unprocessed natural gas. In addition, QEP Field Services owns treating facilities in northwest Louisiana, which remove CO_2 from the natural gas stream, that have an aggregate treating capacity of 600 MMcf per day of untreated natural gas. QEP Field Services also owns compression facilities and field dehydration and measurement systems. The 21-mile, 20-inch diameter pipeline owned by Rendezvous Pipeline can deliver up to 300 MMcf of natural gas per day to the Kern River Pipeline. QEP Field Services partnership facilities include the RGS system, consisting of 300 miles of gathering lines and associated field equipment, the UBFS system, which consists of 78 miles of gathering lines and associated field equipment and the Three Rivers system, which consists of 52 miles of gathering lines and associated field equipment.

In January 2011, QEP Field Services put into service the 150 MMcf per day cryogenic Iron Horse processing plant, an expansion of its Stagecoach processing complex in the Uinta Basin of eastern Utah. The plant predominantly provides fee-based processing services to third parties. In July 2011, QEP Field Services commissioned the 420 MMcf per day Blacks Fork II cryogenic processing plant, an expansion of its Blacks Fork processing complex located in the Green River Basin of southwestern Wyoming. The Blacks Fork complex is about 100 miles south of QEP's operations at Pinedale. QEP expects that the Blacks Fork II plant at full capacity will be able to extract an incremental net 16,000 bbls per day of NGL.

ENERGY MARKETING – QEP Marketing

QEP Marketing, through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas storage reservoir in southwestern Wyoming. The reservoir has a gas storage capacity of approximately 8 Bcf, comprised of an inventory of approximately 4 Bcf of QEP Marketing-owned cushion gas and working gas storage capacity of about 4 Bcf.

ITEM 3. LEGAL PROCEEDINGS

QEP is involved in various commercial and regulatory claims and litigation and other legal proceedings that arise in the ordinary course of its business. Management does not believe any of them will have a material adverse effect on the Company's financial position, results of operations or cash flows. A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. Disclosures are provided for contingencies reasonably likely to occur which would have a material adverse effect on the Company's financial position, results of operations or cash flows. Some of the claims involve highly complex issues relating to liability, damages and other matters subject to substantial uncertainties and, therefore, the probability of liability or an estimate of loss cannot be reasonably determined.

Environmental Claims

United States of America v. QEP Field Services, Civil No. 208CV167, U.S. District Court for Utah. The U.S. Environmental Protection Agency (EPA) alleges that QEP Field Services (f/k/a Questar Gas Management) violated the Clean Air Act (CAA) and seeks substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. Individual members of the Ute Indian Tribe's Business Committee intervened as co-plaintiffs asserting the same CAA claims as the federal government. EPA contends that the potential to emit, on a hypothetically uncontrolled basis, for these facilities renders them "major sources" of emissions for criteria and hazardous air pollutants even though controls were installed and operated by QEP Field Services. Categorization of the facilities as "major sources" affects the particular regulatory program and requirements applicable to those facilities. EPA claims that QEP Field Services failed to obtain the necessary major source pre-construction or modification permits, and failed to comply with hazardous air-pollutant regulations for monitoring, testing and reporting, among other requirements. QEP Field Services contends that its facilities have pollution controls installed, as part of their operational design, that reduce their actual air emissions below major source thresholds, rendering them subject to different regulatory requirements applicable to non-major sources. QEP Field Services has vigorously defended against EPA's claims, and believes that the major source permitting and regulatory requirements at issue can be legally avoided by applying EPA's prior permitting practice for similar facilities elsewhere in Indian Country, among other defenses. Because of the complexities and uncertainties of this legal dispute, it is difficult to predict all reasonably possible outcomes; however, management believes the Company has accrued a reasonable loss contingency that is an immaterial amount, for the anticipated most likely outcome.

QEP Energy v. U.S. Environmental Protection Agency, No. 09-9538, U.S. Court of Appeals for the 10th Circuit. On July 10, 2009, QEP Energy filed a petition with the U.S. 10th Circuit Court of Appeals challenging an administrative compliance order dated May 12, 2009 (Order), issued by EPA which asserts that QEP Energy's Flat Rock 14P well in the Uinta Basin and associated equipment is a major source of hazardous air pollutants and its operation fails to comply with certain regulations of the CAA. The Order required immediate compliance. QEP Energy denied that the drilling and operation of the 14P well and associated equipment violated any provisions of the CAA. QEP and EPA entered into an administrative order on consent, effective June 17, 2011, resolving all disputes associated with prospective CAA compliance at the Flat Rock 14P well. Among other matters, the order requires installation of pollution control equipment to destroy vapors from the well's dehydration equipment and ongoing monitoring and reporting associated with operation of that control equipment.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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

QEP's common stock is listed and traded on the New York Stock Exchange (NYSE:QEP). As of January 31, 2012, QEP had 7,793 shareholders of record. The declaration and payment of dividends are at the discretion of QEP's Board of Directors and the amount thereof will depend on QEP's results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors. The Company expects that cash dividends will continue to be paid in the future. Following is a summary of the high and low sales price per share of QEP's common stock on the NYSE and quarterly dividends paid per share:

	High price	Low price	Dividend
		(per share)	
2011			
First quarter	$ 42.00	$ 35.78	$ 0.02
Second quarter	43.70	37.11	0.02
Third quarter	45.20	26.52	0.02
Fourth quarter	38.44	23.56	0.02
			$ 0.08
2010			
First quarter [(1)]	$ -	$ -	$ -
Second quarter [(1)]	-	-	-
Third quarter	35.15	27.90	0.02
Fourth quarter	38.33	29.54	0.02
			$ 0.04

(1) Public trading of the common stock of the Company commenced on July 1, 2010.

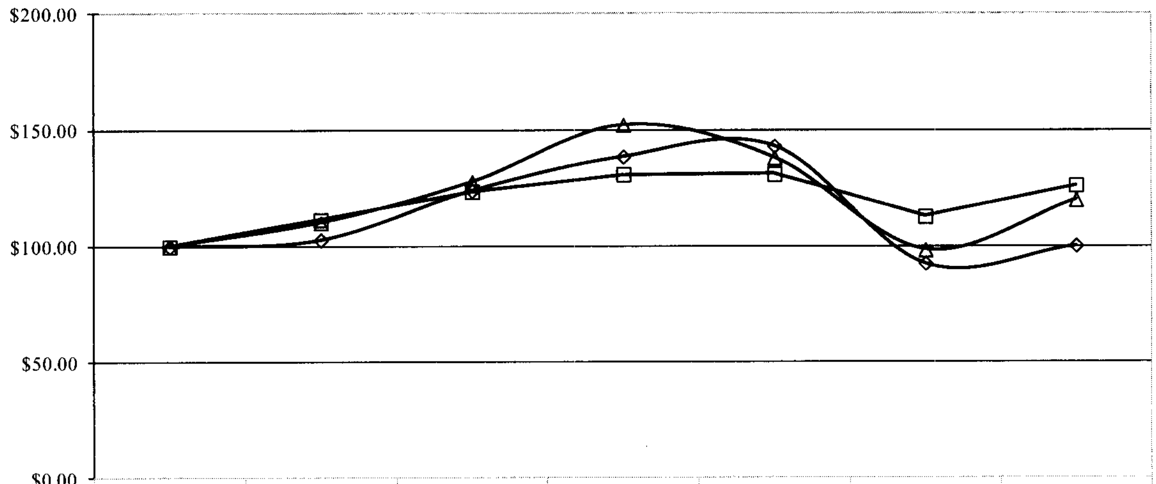
Stockholder Return Performance Presentation

The performance presentation shown below is being furnished as required by applicable rules of the SEC and was prepared using the following assumptions:

- A $100 investment was made in QEP common stock, the S&P 500 Index and the Company's peer group as of July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;
- Investment in the Company's peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of each period for which a return is indicated; and
- Dividends were reinvested on the relevant payment dates.

QEP's peer group, as defined, consists of the following companies: Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Quicksilver Resources, Inc., Range Resources Corporation, Southwestern Energy Company, Ultra Petroleum Corporation and Whiting Petroleum Corporation. Petrohawk Energy Corporation was removed from the peer group in 2011, due to its acquisition by BHP Billington. Management believes this peer group provides a meaningful comparison based upon the Company's review of asset size, geographic location of assets, market capitalization, revenues, culture and performance, among other things.

Comparison of Cumulative Total Return Since Inception
Assumes Initial Investment of $100
December 2011



	7/1/2010	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	12/31/2011
QEP Resources, Inc.	100.00	102.90	124.03	138.56	143.03	92.61	100.30
S&P 500 Index - Total Returns	100.00	111.65	123.66	130.98	131.11	112.93	126.27
Peer Group	100.00	110.30	127.71	152.27	138.07	98.46	120.07

Purchases of equity securities by the issuer and affiliated purchasers

The following repurchases of QEP shares were made by an affiliated purchaser, QEP Resources Education Foundation, during the fourth quarter of 2011:

Period	Total number of shares purchased [1]	Weighted-average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be repurchased under the plans or programs
October 1, 2011 - October 31, 2011	-	$ -	-	-
November 1, 2011 - November 30, 2011	7,475	$ 37.3425	-	-
December 1, 2011 - December 31, 2011	-	$ -	-	-
	7,475	$ 37.3425	-	-

[1] QEP Resources Education Foundation, an affiliated purchaser, purchased the shares in open-market transactions. These purchases were not made pursuant to a publicly announced plan or program.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2011, is provided in the table below. Refer to Item 7 and Item 8 in Part II of this annual report for discussion of facts affecting the comparability.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
			(in millions)		
Results of Operations [1]					
Revenues [2]	**$ 3,159.2**	$ 2,300.6	$ 2,011.2	$ 2,360.9	$ 1,713.7
Operating income	**505.9**	545.3	585.5	933.2	584.1
Income from continuing operations	**270.4**	285.9	215.4	520.6	361.6
Discontinued operations, net of income tax	**-**	43.2	80.7	73.9	59.2
Net income attributable to QEP	**267.2**	326.2	293.5	585.5	420.8
Earnings per common share attributable to QEP					
Basic from continuing operations	**$ 1.51**	$ 1.61	$ 1.23	$ 2.96	$ 2.11
Basic from discontinued operations	**-**	0.25	0.46	0.43	0.34
Basic total	**$ 1.51**	$ 1.86	$ 1.69	$ 3.39	$ 2.45
Diluted from continuing operations	**$ 1.50**	$ 1.60	$ 1.21	$ 2.90	$ 2.05
Diluted from discontinued operations	**-**	0.24	0.46	0.42	0.34
Diluted total	**$ 1.50**	$ 1.84	$ 1.67	$ 3.32	$ 2.39
Dividends	**$ 0.08**	$ 0.04	$ -	$ -	$ -
Weighted-average common shares outstanding					
Used in basic calculation	**176.5**	175.3	174.1	172.8	172.0
Used in diluted calculation	**178.4**	177.3	176.3	176.1	175.9
Financial Position					
Total Assets at December 31,	**$ 7,442.7**	$ 6,785.3	$ 6,481.4	$ 6,342.7	$ 3,821.6
Capitalization at December 31,					
Long-term debt	**1,679.4**	1,530.8	1,348.7	1,299.1	499.3
Total equity	**3,352.1**	3,063.1	2,808.7	2,779.4	1,860.1
Total Capitalization	**$ 5,031.5**	$ 4,593.9	$ 4,157.4	$ 4,078.5	$ 2,359.4
Cash Flow From Continuing Operations					
Net cash provided by operating activities	**$ 1,292.6**	$ 997.5	$ 1,149.4	$ 1,224.7	$ 807.0
Capital expenditures	**(1,431.1)**	(1,469.0)	(1,196.9)	(2,136.7)	(838.9)
Net cash used in investing activities	**(1,422.9)**	(1,390.5)	(1,146.4)	(2,021.0)	(867.9)
Net cash provided by (used in) financing activities	**130.3**	373.7	(8.8)	818.7	44.1
Non-GAAP Measures					
Adjusted EBITDA [3]	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	$ 1,310.7	$ 890.7

(1) QEP completed a Spin-off from Questar in June 2010 as discussed in more detail in the Explanatory Note in Part I, Item 1 of this Annual Report on Form 10-K. As a result of the Spin-off, Wexpro's financial results have been reflected as discontinued operations and all prior periods have been recast.

(2) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. This change had no impact on net income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

(3) Adjusted EBITDA is a non-GAAP measure. Management defines Adjusted EBITDA as net income before the following items: discontinued operations, unrealized gain and losses on basis-only swaps, gains and losses from asset sales, interest and other income, income taxes, interest expense, separation costs, loss on early extinguishment of debt, depreciation, depletion and amortization, abandonment and impairment, and exploration expense. Management focuses on Adjusted EBITDA to assess the Company's operating results. Management believes Adjusted EBITDA is an important measure of the Company's cash flow and liquidity and its ability to incur and service debt, fund capital expenditures and make distributions to shareholders, and an important measure for comparing the Company's financial performance to other gas and oil producing companies. In addition, Adjusted EBITDA is a part of the Company's debt covenants as defined in its revolving credit agreement.

The following table reconciles QEP Resources' net income to Adjusted EBITDA:

	Year Ended December 31,				
	2011	2010	2009	2008	2007
			(in millions)		
Adjusted EBITDA					
Net income attributable to QEP	**$ 267.2**	$ 326.2	$ 293.5	$ 585.5	$ 420.8
Net income attributable to noncontrolling interest	**3.2**	2.9	2.6	9.0	$ -
Net income	**270.4**	329.1	296.1	594.5	420.8
Discontinued operations, net of tax	**-**	(43.2)	(80.7)	(73.9)	(59.2)
Income from continuing operations	**270.4**	285.9	215.4	520.6	361.6
Unrealized gain (loss) on basis-only swaps	**(117.7)**	(121.7)	164.0	79.2	(5.7)
Net (gain) loss from asset sales	**(1.4)**	(12.1)	(1.5)	(60.4)	0.6
Interest and other income	**(4.1)**	(2.3)	(4.5)	(10.2)	(7.8)
Income taxes	**154.4**	167.0	117.6	283.6	211.3
Interest expense	**90.0**	84.4	70.1	61.7	33.6
Separation costs	**-**	13.5	-	-	-
Loss from early extinguishment of debt	**0.7**	13.3	-	-	-
Depreciation, depletion and amortization	**765.4**	643.4	559.1	361.5	263.9
Abandonment and impairment	**218.4**	46.1	20.3	45.4	11.2
Exploration expenses	**10.5**	23.0	25.0	29.3	22.0
Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	$ 1,310.7	$ 890.7

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the Consolidated Financial Statements and related notes included in Item 8 of this Annual Report on Form 10-K.

The following information updates the discussion of QEP's financial condition provided in its 2010 Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2011 versus December 31, 2010 and December 31, 2010 versus December 31, 2009. During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. The impact of this revision is immaterial to the accompanying financial statements and has no effect on net income. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with three major lines of business – gas and oil exploration and production, midstream field services, and energy marketing – which are conducted through three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and NGL;
- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering and processing, compression and treating services, for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Reincorporation Merger and Spin-off

Effective May 18, 2010, Market Resources, then a wholly owned subsidiary of Questar, merged with and into QEP, a Delaware corporation and a newly formed, wholly owned subsidiary of Questar, in order to reincorporate in the State of Delaware. The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. On June 30, 2010, Questar distributed to existing Questar stockholders all of the shares of common stock of QEP in a tax-free, pro-rata spin-off, establishing QEP as an independent, publicly traded company. In connection with the Spin-off, QEP distributed Wexpro, a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

Outlook

The Company has substantial acreage positions and operations in some of North America's most important hydrocarbon resource plays, including the Bakken/Three Forks, Pinedale, Haynesville and Woodford "Cana" Shale. These resource plays are characterized by unconventional oil or natural gas accumulations in continuous tight sands or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that aside from wells abandoned due to mechanical issues, the Company does not expect to drill many unsuccessful wells. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high density and repeatable drilling and completion operations. The Company has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore United States that provide a solid base for consistent organic production and reserve growth. QEP believes that it has one of the lowest cash cost structures among its exploration and production company peers. However, in certain of its resource plays, the Company has experienced rising completed well costs, which could impact future drilling plans.

While predominantly a natural gas producer, the Company has increased its focus on growing the relative proportion of crude oil and NGL production in its exploration and production business. QEP Energy oil and NGL production increased by approximately 54% during the year ended December 31, 2011 to 6,456.9 Mbbl, and oil and NGL revenue accounted for approximately 29% of net production revenues (including realized gains and losses on all settled derivative contracts) during the year ended December 31, 2011, compared to 19% and 12% during the years ended December 31, 2010 and 2009, respectively. QEP Energy oil and NGL production increased by approximately 22% during the year ended December 31, 2010 when compared to the 2009 period. The increase in NGL sales volumes during 2011 was a result of the fee-based processing agreement entered into with QEP Field Services effective August 1, 2011, shortly after the start-up of the Blacks Fork II plant in July 2011 and the liquids recovered for QEP Energy by third party processers associated with development of liquids-rich plays in the Midcontinent and in the Bakken/Three Forks formations. The Company has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas plays due to current depressed natural gas prices and the natural gas forward price.

While QEP believes that it can grow its production and reserves from its extensive inventory of drilling locations, the Company also evaluates acquisition opportunities that might have the potential to create significant long-term value. QEP believes that its experience, expertise and substantial presence in the Southern and Northern Regions, combined with its low-cost operating structure and financial strength, enhance its ability to pursue acquisition opportunities in those geographic areas.

The Company also owns and operates gathering and transmission pipelines and natural gas processing and treatment facilities in many of its core producing areas, which allows the Company to promptly connect its wells, better control its costs, and generate a significant revenue stream by providing gathering and processing services to third parties. Net income from QEP's midstream business accounted for approximately 58% of the Company's total net income from continuing operations attributable to QEP during the year ended December 31, 2011, compared to 32% and 33% during the years ended December 31, 2010 and 2009. QEP's midstream net income as a percentage of total Company net income increased in 2011 due in part to impairment charges at QEP Energy which decreased its share of total Company net income as compared to prior periods.

Financial and Operating Results

During the year ended December 31, 2011, QEP had strong production growth from QEP Energy, its exploration and production business, and QEP Field Services, its gathering and processing business. Although crude oil and NGL prices decreased in the second half of 2011 from the first half of 2011, QEP Energy benefitted from higher production and higher crude oil and NGL prices during the year ended December 31, 2011, as compared to the 2010 and 2009 periods. QEP Field Services benefitted during the year ended December 31, 2011, from the Iron Horse plant having three full quarters of operations, the commencement of the Blacks Fork II processing plant in the second half of 2011 and continued robust gas processing margins.

During the years ended December 31, 2011, 2010, and 2009, QEP Energy reported production of 275.2 Bcfe, 229.0 Bcfe and 189.5 Bcfe, respectively. During the year ended December 31, 2011, the Southern and Northern Regions contributed 56% and 44%, respectively, of total equivalent production. QEP Energy continues to focus on the controllable cash cost of production per Mcfe. The Company defines cash cost of production as the sum of lease operating expense, general and administrative expense, a portion of total QEP interest expense that is allocated to QEP Energy based on intercompany agreements and production taxes. Cash operating costs for QEP Energy were $1.56 per Mcfe during the year ended December 31, 2011 compared to $1.58 per Mcfe and $1.68 per Mcfe for the years ended December 31, 2010 and 2009. The decrease was the result of increased production volumes partially offset by higher overall production costs. QEP Energy reported record production of 275.2 Bcfe in 2011 and all divisions, other than the Uinta Basin, recorded production that was greater than in 2010. Year-end proved reserves increased by 19% over the prior year to 3.61 Tcfe.

QEP Field Services reported gathering system throughput of 1.4 million MMBtu per day during the year ended December 31, 2011, up from 1.3 million MMBtu per day and 1.1 million MMBtu per day for the years ended December 31, 2010 and 2009. During the year ended December 31, 2011, QEP Field Services reported a 42% increase in NGL sales volumes to a total of 141.8 million gallons. The increase in NGL sales volumes along with a 38% increase in the per unit NGL margin (NGL revenue less fuel and shrinkage and transportation and handling costs) resulted in a 95% increase to the keep-whole processing margin during the year ended December 31, 2011.

During the first quarter of 2011, QEP Field Services commenced operations of the 150 MMcf per day cryogenic Iron Horse processing plant, an expansion of its Stagecoach processing complex in the Uinta Basin of eastern Utah. This plant predominantly provides fee-based processing services to third-parties. During the third quarter of 2011, QEP Field Services commissioned the 420 MMcf per day Blacks Fork II cryogenic processing plant, an expansion of its Blacks Fork processing complex located in the Green River Basin of southwestern Wyoming. The Blacks Fork complex is about 100 miles south of QEP's operations at Pinedale. QEP expects that the Blacks Fork II plant at full capacity will be able to extract an incremental net 16,000 Bbls per day of NGL.

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016, and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The agreement also contains provisions which would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for two additional one-year periods.

During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair values. Of the $195.2 million impairment charge, $163.5 million were related to properties in the Northern Region with the remaining $31.7 million related to properties in the Southern Region. See Item 8, footnote 1, "Summary of Significant Accounting Policies", of this Annual Report on Form 10-K, for additional information regarding the impairment.

Factors Affecting Results of Operations

Oil and Natural Gas Prices

Historically, prices received for QEP's natural gas, NGL and crude oil production have been volatile and unpredictable, and that volatility is expected to continue. In recent years, the domestic natural gas supply has grown faster than natural gas demand, driven by advances in technology, including horizontal drilling and hydraulic fracturing, which have allowed producers to extract increasing amounts of natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supply has put downward pressure on natural gas prices, while concern about the global economy and other factors has caused the price of crude oil to decrease in the second half of 2011 from the first half of 2011, although they remain higher during the year ended December 31, 2011 than comparable 2010 and 2009 prices. Changes in the market prices for crude oil, natural gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, liquidity, rate of growth, costs of goods and services required to drill and complete wells, and the carrying value of its oil and natural gas properties. For example, despite a 16% increase in natural gas production during the year ended December 31, 2011, natural gas revenues increased by only 3% due to significantly lower net realized natural gas prices. Similarly, during the year ended December 31, 2010, natural gas production increased 21%, yet natural gas revenues increased by only 2% due to lower net realized natural gas prices.

QEP uses commodity derivatives to reduce the variability of the prices QEP receives for a portion of its production and to provide a minimum revenue stream. In general, QEP plans to hedge approximately 50% of its forecasted production by the end of the first quarter of the current year. As of December 31, 2011, QEP Energy had approximately 49% of its forecasted 2012 natural gas, oil and NGL production covered with fixed-price swaps or costless collars, assuming 2012 annual production of 307.5 Bcfe. See "Quantitative and Qualitative Disclosures about Market Risk – Commodity Derivative Transactions" for further details concerning QEP's commodity derivatives transactions. In addition, as a result of the continued spread between oil and natural gas prices, the Company has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas projects in its portfolio.

Unrealized Derivative Gains and Losses

Unrealized gains and losses that result from mark-to-market valuations of derivative positions that are not accounted for as cash flow hedges were reflected as unrealized commodity derivative gains or losses in the Company's income statement during the years ended December 31, 2011, 2010 and 2009. In addition, the Company has elected to discontinue hedge accounting beginning January 1, 2012 and future unrealized gains and losses that result from mark-to-market valuations of all derivative positions will be reflected as unrealized commodity derivative gains or losses in the Company's income statement. See Item 8, footnote 1, "Summary of Significant Accounting Policies," of this annual report on Form 10-K for additional information regarding the discontinuance of hedge accounting. Payments due to or from counterparties in the future on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of QEP's production. QEP has incurred significant unrealized gains and losses in prior periods and may continue to incur these types of gains and losses in the future.

Blacks Fork II Processing Plant

The completion and start-up of the new Blacks Fork II processing plant resulted in increased NGL production in QEP Field Services and QEP Energy in 2011. As part of the agreement, QEP Energy and QEP Field Services recorded line pack for the NGL line-fill requirements which is recorded as inventory on each of the respective company's balance sheet at December 31, 2011.

In conjunction with the start up of the Blacks Fork II plant, QEP Energy entered into a fee-based processing agreement with QEP Field Services to process QEP Energy's share of Pinedale gas. As a result, about 46% of the NGL recovered at the Blacks Fork II plant will be accounted for as NGL production in QEP Energy, with about 40% included in the keep-whole volumes in QEP Field Services. The remaining 14% relates to non-QEP royalty volumes.

Global Economy and the European Debt Crisis

QEP remains hopeful for a continued recovery of the global economy, however, continues to monitor the outlook of the global economy, including the European debt crisis and its potential impact on global economic growth and the banking and financial sectors, the United States federal budget deficit, and commodity prices. QEP expects natural gas prices to remain low in the United States if the natural gas drilling rig counts remain near current levels, natural gas storage remains high and natural gas production continues to grow. QEP expects oil prices to remain at or above current levels if the global economy continues its recovery. Disruption to the global oil supply system or other factors, could trigger oil price volatility with sharp increases in the crude oil price that could be followed by sharp declines in the price the Company may receive for its oil production. Because of the global economic outlook and the uncertainty around the commodity pricing environment, QEP continues to plan its capital spending program and financial flexibility appropriately.

Potential for Future Asset Impairments

The United States natural gas market remains weak. A further decrease in forward natural gas prices during 2012 could result in additional impairment charges. Certain of the Company's properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These assets are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. The cash flow model that the Company uses to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward natural gas prices alone could result in an impairment of properties that are sensitive to declines in natural gas prices. A significant drop in oil prices could also trigger impairment. For additional information see Item 1A "Risk Factors" and see Item 8. Note 1 "Significant Accounting Policies."

RESULTS OF OPERATIONS

Net Income

QEP Resources net income from continuing operations attributable to QEP in 2011 was $267.2 million or $1.50 per diluted share, compared to $283.0 million or $1.60 per diluted share in 2010. The decrease in 2011 was due to the $99.2 million, or 49%, decline in QEP Energy's net income, partially offset by a $63.4 million, or 70%, increase in QEP Field Services' net income. QEP Energy's net income declined in 2011 because of a non-cash, price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. Offsetting the decline at QEP Energy, QEP Field Services' increase in net income was driven by higher gathering and processing margins and increased throughput volumes. QEP Resources net income from continuing operations attributable to QEP in 2010 was $70.2 million, or 33% higher than the 2009 period. The increase in 2010 net income was primarily driven by increased net income at both QEP Energy and QEP Field Services. QEP Energy's 2010 increase in net income was the result of higher production and higher net realized crude oil and NGL prices in 2010, partially offset by lower net realized natural gas prices. QEP Field Services' 2010 increase in net income was due to higher gathering and processing margins and increased throughput volumes. Following are comparisons of net income from continuing operations attributable to QEP by line of business:

	Year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
QEP Energy	**$ 104.7**	$ 203.9	$ 134.9	**$ (99.2)**	$ 69.0
QEP Field Services	**154.5**	91.1	69.4	**63.4**	21.7
QEP Marketing and other	**8.4**	6.7	8.5	**1.7**	(1.8)
QEP Resources	**(0.4)**	(18.7)	-	**18.3**	(18.7)
Net income from continuing operations attributable to QEP	**$ 267.2**	$ 283.0	$ 212.8	**$ (15.8)**	$ 70.2
Earnings per diluted share from continuing operations	**$ 1.50**	$ 1.60	$ 1.21	**$ (0.10)**	$ 0.39
Average diluted shares	**178.4**	177.3	176.3	**1.1**	1.0

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company's cash flow and liquidity and an important measure for comparing the Company's financial performance to other gas and oil producing companies. Management defines Adjusted EBITDA as net income before the following items: depreciation, depletion and amortization, abandonment and impairment, interest and other income, interest expense, separation costs, loss on early extinguishment of debt, income taxes, unrealized gain and losses on basis-only swaps, discontinued operations, gains and losses from assets sales, and exploration expense. During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs to align with industry practice and GAAP. This revised disclosure does not change current or prior period disclosure of net income and Adjusted EBITDA. For additional information, see Item 8, Note 1 "Significant Accounting Policies" for additional details. Following are comparisons of Adjusted EBITDA by line of business:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
QEP Energy	**$ 1,057.5**	$ 926.2	$ 988.0	**$ 131.3**	$ (61.8)
QEP Field Services	**320.3**	203.9	162.6	**116.4**	41.3
QEP Marketing and other	**8.8**	10.4	14.9	**(1.6)**	(4.5)
Total Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	**$ 246.1**	$ (25.0)

Adjusted EBITDA increased 22% to $1,386.6 million for the year ended December 31, 2011, compared to $1,140.5 million in the 2010 period, despite an 11% decrease in net realized natural gas prices. The impact of lower net realized natural gas prices during the year ended December 31, 2011 was offset by a 20% increase in total production, 30% higher net realized crude oil prices and 22% higher net realized NGL prices in QEP Energy, along with increased gathering margins (22% higher) and processing margins (93% higher) in QEP Field Services. Adjusted EBITDA decreased only 2% during the year ended December 31, 2010 from the $1,165.5 million during the year ended December 31, 2009, despite a decrease in net realized natural gas prices of 23%. The large decrease in natural gas prices in the 2010 period compared to the 2009 period was offset by a 21% increase in total production, 29% higher net realized crude oil prices and 23% higher net NGL prices in QEP Energy. During the year ended December 31, 2010, QEP Field Services gathering margins increased 23% and processing margins increased 29% from the year ended December 31, 2009.

A reconciliation of adjusted EBITDA to net income follows:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Net income attributable to QEP Resources	**$ 267.2**	$ 326.2	$ 293.5	**$ (59.0)**	$ 32.7
Net income attributable to non-controlling interest	**3.2**	2.9	2.6	**0.3**	0.3
Net income	**270.4**	329.1	296.1	**(58.7)**	33.0
Discontinued operations, net of tax	**-**	(43.2)	(80.7)	**43.2**	37.5
Income from continuing operations	**270.4**	285.9	215.4	**(15.5)**	70.5
Unrealized gain on basis-only swaps	**(117.7)**	(121.7)	164.0	**4.0**	(285.7)
Net gain from asset sales	**(1.4)**	(12.1)	(1.5)	**10.7**	(10.6)
Interest and other loss (income)	**(4.1)**	(2.3)	(4.5)	**(1.8)**	2.2
Income taxes	**154.4**	167.0	117.6	**(12.6)**	49.4
Interest expense	**90.0**	84.4	70.1	**5.6**	14.3
Separation costs	**-**	13.5	-	**(13.5)**	13.5
Loss on early extinguishment of debt	**0.7**	13.3	-	**(12.6)**	13.3
Depreciation, depletion and amortization	**765.4**	643.4	559.1	**122.0**	84.3
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Adjusted EBITDA	**$ 1,386.6**	$ 1,140.5	$ 1,165.5	**$ 246.1**	$ (25.0)

Revenue, Volumes and Prices

	Year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Revenues					
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2	**$ 33.8**	$ 18.1
Oil sales	**324.2**	198.1	141.3	**126.1**	56.8
NGL sales	**129.7**	47.9	22.5	**81.8**	25.4
Gathering, processing and other	**380.9**	251.3	218.4	**129.6**	32.9
Purchased gas and oil sales	**1,085.3**	598.0	441.8	**487.3**	156.2
Total Revenues	**$ 3,159.2**	$ 2,300.6	$ 2,011.2	**$ 858.6**	$ 289.4

QEP Energy's revenues for the years ended December 31, 2011 and 2010, resulting from the sale of natural gas, oil and NGLs increased primarily due to increased production volumes and higher oil and NGL prices, offset by lower prices for natural gas, as follows:

	Year ended December 31, 2011			
	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Revenues				
2010 revenues	$ 1,205.3	$ 198.1	$ 47.9	$ 1,451.3
Changes associated with volumes (1)	193.2	50.7	58.1	302.0
Changes associated with prices (2)	(159.4)	75.4	23.7	(60.3)
2011 revenues	**$ 1,239.1**	**$ 324.2**	**$ 129.7**	**$ 1,693.0**

	Year ended December 31, 2010			
	Natural Gas	Oil	NGLs	Total
	(in millions)			
QEP Energy Revenues				
2009 revenues	$ 1,187.2	$ 141.3	$ 22.5	$ 1,351.0
Changes associated with volumes (1)	246.5	12.1	16.6	275.2
Changes associated with prices (2)	(228.4)	44.7	8.8	(174.9)
2010 revenues	$ 1,205.3	$ 198.1	$ 47.9	$ 1,451.3

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by the average realized price or fee for the year ended December 31, 2010 or 2009.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in realized prices or fee from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by volume for the year ended December 31, 2010 or 2009.

QEP Field Services revenues also increased for the years ended December 31, 2011 and 2010, as a result of higher volumes, improved processing and gathering fees in 2011 as compared to 2010, and higher gathering and processing volumes, and higher NGL prices and gathering fees in 2010 as compared to 2009, as follows:

	For the year ended December 31, 2011			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
2010 revenues	$ 94.8	$ 35.2	$ 189.2	$ 319.2
Changes associated with volumes (1)	39.3	2.3	7.8	49.4
Changes associated with fees (2)	45.9	18.4	32.6	96.9
2011 revenues	**$ 180.0**	**$ 55.9**	**$ 229.6**	**$ 465.5**

	For the year ended December 31, 2010			
	NGLs	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
2009 revenues	$ 71.9	$ 32.6	$ 160.1	$ 264.6
Changes associated with volumes (1)	(1.0)	2.6	24.0	25.6
Changes associated with fees (2)	23.9	-	5.1	29.0
2010 revenues	$ 94.8	$ 35.2	$ 189.2	$ 319.2

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by the average realized price or fee for the year ended December 31, 2010 or 2009.

(2) The revenue variance attributed to the change in fees is calculated by multiplying the change in realized prices or fee from the year ended December 31, 2011 or 2010, to the year ended December 31, 2010 or 2009, by volume for the year ended December 31, 2010 or 2009.

Purchased gas and oil sales increased by $487.3 million, or 81% during the year ended December 31, 2011 from 2010. The increase in 2011 was primarily due to QEP Energy's additional revenues of $509.8 million related to gas purchases made in northwest Louisiana to utilize firm transportation capacity and the subsequent sale of those gas purchases. Purchased gas and oil sales increased $156.2 million, or 35%, during the year ended December 31, 2010 compared to 2009. The 2010 increase was the result of higher natural gas prices and increased sales volumes at QEP Marketing.

Reserves

QEP Energy's proved reserves in major operating areas at December 31, 2011 and 2010 are summarized below:

	2011		2010	
	(Bcfe)	(% of total)	(Bcfe)	(% of total)
Southern Region				
Haynesville/Cotton Valley	**782.9**	**22**	728.3	24
Midcontinent	**518.7**	**14**	442.2	15
Northern Region				
Pinedale Anticline	**1,531.0**	**42**	1,348.9	44
Uinta Basin	**393.6**	**11**	212.8	7
Rockies Legacy	**387.6**	**11**	298.5	10
Total QEP Energy	**3,613.8**	**100**	3,030.7	100

Production

QEP Energy reported production of 275.2 Bcfe during the year ended December 31, 2011 compared to 229.0 Bcfe and 189.5 Bcfe for the years ended December 31, 2010 and 2009, respectively. On an energy-equivalent basis, crude oil and NGL comprised approximately 14% of QEP Energy's total production for the year ended December 31, 2011, up from 11% for the years ended December 31, 2010 and 2009. A summary of production is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy production volumes					
Natural gas (Bcf)	**236.4**	203.8	168.7	**32.6**	35.1
Oil (Mbbl)	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1
NGL (Mbbl)	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8
Total production (Bcfe)	**275.2**	229.0	189.5	**46.2**	39.5
Average daily production (MMcfe)	**753.9**	627.4	519.1	**126.5**	108.3

A summary of natural gas production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Natural gas (Bcf)					
Southern Region					
Haynesville/Cotton Valley	**107.1**	79.3	46.9	**27.8**	32.4
Midcontinent	**32.9**	30.8	32.7	**2.1**	(1.9)
Northern Region					
Pinedale Anticline	**69.3**	65.1	58.9	**4.2**	6.2
Uinta Basin	**14.9**	14.9	16.7	**-**	(1.8)
Rockies Legacy	**12.2**	13.7	13.5	**(1.5)**	0.2
Total production	**236.4**	203.8	168.7	**32.6**	35.1

A summary of oil production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Oil (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**51.0**	78.4	121.1	**(27.4)**	(42.7)
Midcontinent	**835.3**	644.3	775.1	**191.0**	(130.8)
Northern Region					
Pinedale Anticline	**583.8**	551.8	486.9	**32.0**	64.9
Uinta Basin	**866.7**	957.1	930.7	**(90.4)**	26.4
Rockies Legacy	**1,404.5**	748.2	432.9	**656.3**	315.3
Total production	**3,741.3**	2,979.8	2,746.7	**761.5**	233.1

A summary of NGL production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - NGL (Mbbl)					
Southern Region					
Haynesville/Cotton Valley	**8.4**	5.5	3.3	**2.9**	2.2
Midcontinent	**1,371.2**	997.0	456.1	**374.2**	540.9
Northern Region					
Pinedale Anticline	**1,099.6**	-	-	**1,099.6**	-
Uinta Basin	**106.4**	121.5	151.2	**(15.1)**	(29.7)
Rockies Legacy	**130.0**	101.8	94.4	**28.2**	7.4
Total production	**2,715.6**	1,225.8	705.0	**1,489.8**	520.8

A summary of natural gas equivalent total production by major geographical area is shown in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Total Production (Bcfe)					
Southern Region					
Haynesville/Cotton Valley	**107.5**	79.8	47.7	**27.7**	32.1
Midcontinent	**46.2**	40.6	40.1	**5.6**	0.5
Northern Region					
Pinedale Anticline	**79.4**	68.5	61.8	**10.9**	6.7
Uinta Basin	**20.8**	21.4	23.2	**(0.6)**	(1.8)
Rockies Legacy	**21.3**	18.7	16.7	**2.6**	2.0
Total production	**275.2**	229.0	189.5	**46.2**	39.5

Southern Region – Haynesville/Cotton Valley. Net production in the Haynesville/Cotton Valley area grew 35% to 107.5 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 39% of the Company's total production. During the years ended December 31, 2010 and 2009, Haynesville/Cotton Valley production was 79.8 Bcfe and 47.7 Bcfe, respectively, which represented 35% and 25% of the Company's total production. Haynesville/Cotton Valley area production growth was driven by development drilling in the Haynesville Shale play in northwest Louisiana.

Southern Region – Midcontinent. Net production in the Midcontinent area grew 14% to 46.2 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 17% of the Company's total production. During the years ended December 31, 2010 and 2009, Midcontinent area production was 40.6 Bcfe and 40.1 Bcfe, respectively, which represented 18% and 21% of the Company's total production. Midcontinent area production growth was driven by continued development of the Granite Wash/Atoka Wash play in the Texas Panhandle and the Woodford "Cana" Shale horizontal gas play in the Anadarko Basin of western Oklahoma.

Northern Region – Pinedale Anticline. Net production from the Pinedale Anticline in western Wyoming grew 16% to 79.4 Bcfe during the year ended December 31, 2011 compared to the year ended December 31, 2010 and represented 29% of the Company's total production. During the years ended December 31, 2010 and 2009, Pinedale Anticline production was 68.5 Bcfe and 61.8 Bcfe, respectively, which represented 30% and 33% of the Company's total production. As a result of a new fee-based processing agreement between QEP Energy and QEP Field Services at Blacks Fork II, NGL production at Pinedale for the second half of 2011 was 1,099.6 Mbbl, contrasted with no reportable NGL production in the comparable 2010 and 2009 periods.

Northern Region – Uinta Basin. In the Uinta Basin, production decreased 3% during the year ended December 31, 2011, due to decreased drilling activity, despite a first quarter 2011 prior-period adjustment of QEP's ownership interest within a federal unit, which resulted in a positive adjustment to reported volumes of 1.6 Bcfe. During the year ended December 31, 2010, Uinta production was 1.8 Bcfe lower than in 2009 due to decreased drilling activity resulting from low natural gas prices.

Northern Region – Rockies Legacy. Rockies Legacy net production in 2011 increased by 14% to 21.3 Bcfe. Rockies Legacy production in 2010 was 2.0 Bcfe higher than in 2009. Increases in both 2011 and 2010 were due to increased oil directed drilling activity in the North Dakota Bakken/Three Forks play. Most of QEP's wells in North Dakota have been connected to oil gathering lines during 2011, thereby eliminating future weather-related oil sales interruptions. QEP Energy Rockies Legacy properties include all Northern Region properties except the Pinedale Anticline and the Uinta Basin.

Pricing

During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. See Note 1 "Summary of Significant Accounting Policies," in Item 8, Part II of this Annual Report on Form 10-K, for additional information. Field-level and realized prices (after the impact of all settled commodity derivatives) for natural gas at QEP Energy were lower during the year ended December 31, 2011 than in the 2010 and 2009 comparable periods, while 2011 realized oil and NGL prices were higher than in 2010 and 2009. A regional comparison of QEP Energy's average field-level prices are shown in the following tables:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level natural gas price (per Mcf)					
Southern Region	**$ 4.00**	$ 4.24	$ 3.69	**$ (0.24)**	$ 0.55
Northern Region	**3.87**	4.11	3.30	**(0.24)**	0.81
Average field-level natural gas price	**3.95**	4.18	3.48	**(0.23)**	0.70

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level oil price (per bbl)					
Southern Region	**$ 90.45**	$ 74.93	$ 54.41	**$ 15.52**	$ 20.52
Northern Region	**84.88**	67.62	49.17	**17.26**	18.45
Average field-level oil price	**86.20**	69.39	50.88	**16.81**	18.51

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
QEP Energy - Average field-level NGL price (per bbl)					
Southern Region	**$ 43.66**	$ 35.57	$ 27.15	**$ 8.09**	$ 8.42
Northern Region	**52.00**	54.62	40.56	**(2.62)**	14.06
Average field-level NGL price	**47.76**	39.04	31.82	**8.72**	7.22

A comparison of net realized average natural gas, oil and NGL prices, including the realized losses on basis-only swaps, which did not qualify for hedge accounting and are therefore not included in revenue, are shown in the following table.

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Natural gas (per Mcf)					
Average field-level natural gas price	**$ 3.95**	$ 4.18	$ 3.48	**$ (0.23)**	$ 0.70
Natural gas commodity derivative impact	**1.29**	1.74	3.56	**(0.45)**	(1.82)
Average revenue [(1)]	**5.24**	5.92	7.04	**(0.68)**	(1.12)
Realized losses on basis-only swaps [(2)]	**(0.50)**	(0.60)	(0.16)	**0.10**	(0.44)
Net realized natural gas price	**$ 4.74**	$ 5.32	$ 6.88	**$ (0.58)**	$ (1.56)
Oil (per bbl)					
Average field-level oil price	**$ 86.20**	$ 69.39	$ 50.88	**$ 16.81**	$ 18.51
Oil commodity derivative impact	**0.43**	(2.91)	0.58	**3.34**	(3.49)
Net realized oil price	**$ 86.63**	$ 66.48	$ 51.46	**$ 20.15**	$ 15.02
NGL (per bbl)					
Average field-level NGL price	**$ 47.76**	$ 39.04	$ 31.82	**$ 8.72**	$ 7.22

(1) Reported in revenues in the consolidated income statement.
(2) ·Reported below operating income in the consolidated income statement.

Commodity Derivatives Impact

The Company enters into commodity derivative instruments to manage its exposure to price fluctuations on a portion of its forecasted natural gas and oil production. The impact of QEP's commodity derivatives transactions on the Company's financial statements for the years ended December 31, 2011, 2010 and 2009, is presented below. The net effect of the portion of natural gas basis-only swaps that do not qualify for hedge accounting is reported in the Consolidated Statements of Income below operating income. Derivative positions as of December 31, 2011 and 2010, are summarized in Note 6 to the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

	Year Ended December 31,		
	2011	2010	2009
Volumes subject to commodity derivatives as a percent of gas production - QEP Energy			
Fixed price swaps	**50%**	74%	77%
Costless collars	**12%**	3%	-
Basis-only swaps	-	-	15%
Volumes subject to commodity derivatives as a percent of oil production - QEP Energy			
Fixed price swaps	**3%**	31%	42%
Costless collars	**29%**	24%	-
Volumes subject to commodity derivatives as a percent of propane production - QEP Field Services			
Fixed price swaps	**23%**	-	-

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Impact of settled commodity derivatives on financial statements					
Natural gas sales	**$ 305.5**	$ 353.8	$ 599.3	**$ (48.3)**	$ (245.5)
Oil sales	**1.6**	(8.7)	1.6	**10.3**	(10.3)
Gathering, processing and other	**(0.2)**	-	-	**(0.2)**	-
Purchased gas and oil sales	-	-	27.8	-	(27.8)
Purchased gas and oil expense	**4.3**	3.1	(9.2)	**1.2**	12.3
Loss recognized in income for the ineffective portion of hedges					
Interest and other income	**0.1**	0.2	(0.1)	**(0.1)**	0.3
Impact of settled commodity derivatives that do not qualify for hedge accounting					
Unrealized gain (loss) on basis-only swaps	**117.7**	121.7	(164.0)	**(4.0)**	285.7
Realized (loss) on basis-only swaps	**(117.7)**	(121.7)	(25.6)	**4.0**	(96.1)

The change in unrealized gains and losses on natural gas basis-only swaps increased 2011 net income $75.2 million and increased 2010 net income by $76.3 million. During 2009, the change in unrealized gains and losses on natural gas basis-only swaps decreased net income by $103.3 million. As of December 31, 2009, all of the Company's basis-only swaps had been paired with NYMEX gas fixed-price swaps or price-collars and re-designated as cash flow hedges. Changes in the fair value of these derivative instruments subsequent to their re-designation were recorded in Accumulated Other Comprehensive Income (AOCI), however, changes in the fair value of these derivative instruments occurring prior to their re-designation were recorded in the Consolidated Statement of Income.

Gathering

QEP Field Services posted a 22% increase in gathering margin during the year ended December 31, 2011, primarily due to an increase in the NGL value received from a short-term, third-party processing arrangement for certain volumes in the Northern Region and a 3% increase in the average gathering rate. During the year ended December 31, 2010, gathering margin increased by $28.1 million due to the transfer of the northwest Louisiana gathering system assets from QEP Energy to QEP Field Services, which increased system throughput volume along with increased drilling activity in the Haynesville/Cotton Valley and Pinedale Anticline plays. Gathering system throughput volume was 1.4 million MMBtu per day for the year ended December 31, 2011, up from the 1.3 million MMBtu per day and 1.1 million MMBtu per day during the years ended December 31, 2010 and 2009. The increased volumes in 2011 and 2010 were mainly related to the northwest Louisiana gathering system, as described above, which accounted for 21%, and 16% of the total throughput during the years ended December 31, 2011, and 2010, respectively.

During the year ended December 31, 2011, QEP contracted for 200 million cubic feet per day of gas to a third-party cryogenic processing plant on an interruptible basis, reported in QEP Field Services as "Other gathering revenues." QEP expects "Other gathering revenues" to diminish and to be replaced by keep-whole processing revenues in QEP Field Services and NGL revenues in QEP Energy.

Following is a summary of QEP Field Services' financial and operating results from gathering activities:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Gathering Margin					
Gathering revenues	**$ 161.1**	$ 152.5	$ 127.3	**$ 8.6**	$ 25.2
Other gathering revenues	**68.5**	36.7	32.8	**31.8**	3.9
Gathering expense	**(44.6)**	(37.6)	(36.6)	**(7.0)**	(1.0)
Gathering margin	**$ 185.0**	$ 151.6	$ 123.5	**$ 33.4**	$ 28.1
Operating Statistics					
Natural gas gathering volumes (in millions of MMBtu)					
For unaffiliated customers	**261.2**	276.8	301.2	**(15.6)**	(24.4)
For affiliated customers	**234.2**	198.9	112.6	**35.3**	86.3
Total Gas Gathering Volumes	**495.4**	475.7	413.8	**19.7**	61.9
Average gas gathering revenue (per MMBtu)	**$ 0.33**	$ 0.32	$ 0.31	**$ 0.01**	$ 0.01

Processing

Although a significant portion of the QEP Field Services gas processing services are performed for a volumetric-based fee, a portion of its gas processing agreements result in commodity price exposure. Such agreements are referred to as "keep-whole" processing agreements, whereby the Company has the right to extract NGL recovered at its processing plants and the obligation to replace the Btu equivalent value of such NGL with dry natural gas (the "shrink"). Under these agreements, the Company is exposed to the spread between NGL prices and natural gas prices.

Processing margin increased 93% during the year ended December 31, 2011 compared to the year ended December 31, 2010, due to increased keep-whole processing margins and fee-based processing volumes and lower natural gas prices. The increased keep-whole processing margin was mostly the result of increased NGL prices and volume. NGL prices increased 34% and NGL volumes increased 42% during the year ended December 31, 2011. Fee-based processing revenues increased 53% during the year ended December 31, 2011 compared to 2010, due to an 6% increase in fee-based processing volumes to 240.7 million MMBtu and a 38% increase in the processing fee rate. The increased processing volume was primarily the result of the start-up of the 150 MMcf per day Iron Horse cryogenic processing plant in the Uinta Basin of eastern Utah during the first quarter of 2011 and the start-up of the Blacks Fork II plant in the third quarter of 2011.

Approximately 70%, 78% and 82% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements during the years ended December 31, 2011, 2010 and 2009. The decline in the relative percentage of fee-based revenues was due primarily to the increase in keep-whole processing margins in 2011. Processing margin increased in 2010 compared with 2009 by $19.4 million due to improved NGL prices and lower natural gas costs. The 16.2 million MMBtu increase in fee-based processing volumes in 2010 was driven by increased throughput at QEP Field Services' Stagecoach plant in eastern Utah.

Frac spread, as used in the following table, is defined as the difference between the market value for NGL extracted from the natural gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids and the related transportation and handling costs. Following is a summary of QEP Field Services' processing financial and operating results:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
Processing Margin					
NGL sales	**$180.0**	$ 94.8	$ 71.9	**$ 85.2**	$ 22.9
Processing (fee-based) revenues	**53.7**	35.2	32.4	**18.5**	2.8
Other processing fees	**2.2**	-	0.2	**2.2**	(0.2)
Processing (expense)	**(12.2)**	(11.9)	(10.3)	**(0.3)**	(1.6)
Processing plant fuel and shrinkage (expense)	**(49.2)**	(32.6)	(28.1)	**(16.6)**	(4.5)
Natural gas, oil and NGL transportation and other handling costs	**(9.3)**	-	-	**(9.3)**	-
Processing margin	**$165.2**	$ 85.5	$ 66.1	**$ 79.7**	$ 19.4
Frac spread (NGL sales less processing plant fuel and shrinkage less natural gas, oil and NGL transportation and other handling costs)	**$121.5**	$ 62.2	$ 43.8	**$ 59.3**	$ 18.4
Operating Statistics					
Natural gas processing volumes					
NGL sales (MMgal)	**141.8**	100.2	101.6	**41.6**	(1.4)
Average NGL sales price (per gal)	**$ 1.27**	$ 0.95	$ 0.71	**$ 0.32**	$ 0.24
Fee-based processing volumes (in millions of MMBtu)					
For unaffiliated customers	**122.9**	116.8	110.6	**6.1**	6.2
For affiliated customers	**117.8**	109.4	99.4	**8.4**	10.0
Total fee-based processing volumes	**240.7**	226.2	210.0	**14.5**	16.2
Average fee-based processing revenue (per MMBtu)	**$ 0.22**	$ 0.16	$ 0.15	**$ 0.06**	$ 0.01

Operating Expenses

The following table presents QEP's total operating expenses and the changes from previous reporting periods for the years ended December 31, 2011, 2010 and 2009. The narrative following the below table explains the significant variances between the comparable periods.

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Purchased gas and oil expense	**$ 1,077.1**	$ 589.3	$ 427.8	**$ 487.8**	$ 161.5
Lease operating expense	**145.2**	125.0	125.5	**20.2**	(0.5)
Natural gas, oil and NGL transportation and other handling costs	**102.2**	54.2	38.7	**48.0**	15.5
Gathering, processing and other	**107.3**	83.2	76.2	**24.1**	7.0
General and administrative	**123.2**	107.2	91.7	**16.0**	15.5
Separation costs	**-**	13.5	-	**(13.5)**	13.5
Production and property taxes	**105.4**	82.5	62.9	**22.9**	19.6
Depreciation, depletion and amortization	**765.4**	643.4	559.1	**122.0**	84.3
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Total operating expenses	**$ 2,654.7**	$ 1,767.4	$ 1,427.2	**$ 887.3**	$ 340.2

Purchased gas and oil expense increased in 2011 due to increased purchased gas expense at QEP Energy of $506.4 million. The increased purchased gas expense at QEP Energy relates to gas purchases made in northwest Louisiana to utilize firm transportation capacity. Purchased gas and oil expense increased $161.5 million during the year ended December 31, 2010 compared to the year ended December 31, 2009, due to higher oil and NGL prices and increased volumes.

Lease operating expense increased $20.2 million, or 16% to $145.2 million, during 2011 compared to 2010, driven by a 20% increase in production of natural gas and oil and NGL equivalents during the period. Lease operating expense during 2010 compared to 2009 was essentially flat, despite an increase in production due to the increase in Haynesville and Pinedale volumes, which have lower lease operating expenses.

Natural gas, oil and NGL transportation and other handling costs increased $48.0 million, due primarily to processing costs associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale. Natural gas, oil and NGL transportation and other handling costs increased $15.5 million in 2010 compared to 2009, due primarily to increased natural gas production and related transportation costs at Haynesville/Cotton Valley area. See Item 8, Note 1 "Summary of Significant Accounting Policies," for a discussion of the recasting of transportation and other handling costs.

Gathering, processing and other expense increased by $24.1 million due to higher gathering and processing volumes in 2011 when compared to the 2010 period. Gathering, processing and other expense increased by $7.0 million during the year ended December 31, 2010, compared to the year ended December 31, 2009 also due to higher gathering and processing volumes.

Total QEP general and administrative (G&A) expense increased to $123.2 million for the year ended December 31, 2011, compared with $107.2 million for the year ended December 31, 2010. The increase in 2011 resulted from an increase in the number of employees, increased employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs. QEP total G&A expense increased by $15.5 million, or 17%, during the year ended December 31, 2010 compared to 2009. The 2010 increases primarily related to higher labor, benefits and stock-based compensation expenses.

During the year ended December 31, 2010, QEP reported separation costs of $13.5 million, respectively, related to the Spin-off of QEP Resources, Inc. from Questar Corporation on June 30, 2010. The expenses consisted primarily of QEP's share of certain fees and expenses for financial, legal and tax advisory services and for severance expenses for terminated employees. There were no separation costs in the years ended December 31, 2011 and 2009.

Higher natural gas, oil and NGL production and higher field-level oil and NGL prices, resulted in higher total production and property taxes during the year ended December 31, 2011, partially offset by lower field-level sales prices for natural gas during the same period. Production and property taxes were higher during the year ended December 31, 2010 compared to 2009 as the result of higher field-level natural gas and oil sales prices.

QEP's total depreciation, depletion and amortization expense grew $122.0 million, or 19%, in 2011 from the 2010 comparable period, as a result of increased production at QEP Energy combined with plant additions at QEP Field Services. During the year ended December 31, 2010, QEP's total depreciation, depletion and amortization expense increased to $643.4 million from the $559.1 million during the year ended December 31, 2009, due to increased capital spending at both QEP Energy and QEP Field Services and increased production at QEP Energy.

Exploration expenses were $10.5 million in 2011 compared to $23.0 million in 2010, due to a decrease in dry hole costs of $9.3 million and reduced seismic acquisition costs of $2.5 million. During the year ended December 31, 2010, exploration expenses decreased by $2.0 million, or 8%, despite an $8.7 million charge associated with an unsuccessful exploratory well drilled on the Borie Niobrara prospect in southeastern Wyoming. The overall decrease in 2010 was due to lower geological, geophysical and other exploratory expenses in 2010 compared to 2009.

Abandonment and impairment expenses increased to $218.4 million during the year ended December 31, 2011 compared with $46.1 million during the 2010 period. As discussed earlier, the increase was primarily due to the recognition of a non-cash price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of the Company's mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair value. During the year ended December 31, 2010, abandonment and impairment expenses increased by $25.8 million from the 2009 period, due to higher impairment costs associated with the Company's unproven acreage, which QEP amortizes on a straight-line basis over the primary term of the lease.

CONSOLIDATED RESULTS BELOW OPERATING INCOME

Interest and other income

Interest and other income are comprised primarily of interest earned on investments, gains and losses on warehouse inventory, hedge ineffectiveness and other miscellaneous income. During the year ended December 31, 2011, interest and other income increased by $1.8 million, primarily due to the variance in inventory valuations, offset by lower gains on warehouse inventory sales. Interest and other income decreased $2.2 million in 2010 compared with 2009 due primarily to a valuation adjustment on pipe inventory.

Loss from early extinguishment of debt

The loss from early extinguishment of debt was $0.7 million during the year ended December 31, 2011 compared to $13.3 million in the 2010 period. The loss of $0.7 million in 2011 related to replacing the previous $1.0 billion revolving credit facility with a new $1.5 billion revolving credit facility in the third quarter of 2011. The loss of $13.3 million during 2010 was the result of the purchase of $638.0 million principal amount of senior notes and the termination of a $500 million term loan related to the Spin-off from Questar both occurring in the third quarter of 2010.

Realized and unrealized gain (loss) on basis-only swaps

In the past, the Company has used basis-only swaps to manage the risk of widening basis differentials. Basis-only swaps do not qualify for hedge accounting. As of December 31, 2009, all of the Company's basis-only swaps had been paired with fixed-price swaps and re-designated as cash flow hedges. Fair value changes occurring prior to re-designation were recorded in the Consolidated Statements of Income. Changes in the fair value of the derivative instruments subsequent to the re-designation were recorded in Accumulated Other Comprehensive Income. Realized losses on settlements of basis-only swaps relating to the period prior to re-designation amounted to $117.7 million, $121.7 million and $25.6 million during the years ended December 31, 2011, 2010 and 2009, respectively. Unrealized gains on basis-only swaps amounted to $117.7 million and $121.7 million during the years ended December 31, 2011, and 2010, respectively. Conversely, during the year ended December 31, 2009, QEP reported an unrealized loss on basis-only swaps of $164.0 million.

Interest expense

Interest expense increased 7% to $90.0 million in 2011 compared to 2010 due to December 31, 2011 average debt levels that were approximately $165 million higher than average debt levels in the comparable prior period. During the year ended December 31, 2010, interest expense increased to $84.4 million from $70.1 million in 2009, primarily due to financing activities associated with the issuance of new bonds in 2010 and higher debt levels.

Income taxes

The effective combined federal and state income tax rate was 36.3% for the year ended December 31, 2011, slightly lower than the 36.9% in 2010, but higher than the 35.3% in 2009. The decrease in the combined rate during 2011 was primarily due to the Spin-off which increased the 2010 rate. The 2010 increase in the combined rate was primarily due to a lower state income tax rate in 2009.

DISCUSSION BY LINE OF BUSINESS

QEP Energy

QEP Energy reported net income of $104.7 million in the year ended December 31, 2011, a decrease of 49% from $203.9 million in 2010. As discussed earlier, the primary reason for the decrease was the recognition of a non-cash price-related impairment charge of $195.2 million in the fourth quarter of 2011 on some of QEP Energy's mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. QEP Energy net income also decreased as a result of the continual decline in net realized natural gas prices, which decreased 11% to $4.74 per Mcf in 2011, compared to $5.32 per Mcf in 2010. These natural gas price-related negative impacts were partially offset by a 20% increase in natural gas-equivalent total production and a 30% increase in net realized oil prices in 2011. Net realized oil prices were $86.63 per bbl in 2011 up from $66.48 in 2010. QEP Energy's net income for the year ended December 31, 2010 was $203.9 million, $69.0 million higher than 2009. The 2010 increase over 2009 was due to higher production of 229.0 Bcfe and higher net realized crude oil and NGL prices in 2010, partially offset by lower net realized natural gas prices. Changes in unrealized basis-only swaps increased net income $75.2 million and $76.3 million during the years ended December 31, 2011, and 2010, respectively, compared to decreasing net income by $103.3 million in 2009. Following is a summary of QEP Energy's financial and operating results:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Operating Income					
Revenues					
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2	**$ 33.8**	$ 18.1
Oil sales	**324.2**	198.1	141.3	**126.1**	56.8
NGL sales	**129.7**	47.9	22.5	**81.8**	25.4
Purchased gas sales	**509.8**	-	-	**509.8**	-
Other	**10.4**	5.0	5.0	**5.4**	-
Total Revenues	**2,213.2**	1,456.3	1,356.0	**756.9**	100.3
Operating expenses					
Purchased gas expense	**506.4**	-	-	**506.4**	-
Lease operating expense	**148.2**	127.3	127.5	**20.9**	(0.2)
Natural gas, oil and NGL transportation and other handling costs	**186.0**	125.5	88.7	**60.5**	36.8
General and administrative	**98.4**	78.0	68.0	**20.4**	10.0
Production and property taxes	**99.1**	77.8	58.3	**21.3**	19.5
Depreciation, depletion and amortization	**707.2**	592.5	512.8	**114.7**	79.7
Exploration expenses	**10.5**	23.0	25.0	**(12.5)**	(2.0)
Abandonment and impairment	**218.4**	46.1	20.3	**172.3**	25.8
Total Operating Expenses	**1,974.2**	1,070.2	900.6	**904.0**	169.6
Net gain from asset sales	**1.4**	13.7	1.6	**(12.3)**	12.1
Operating Income	**240.4**	399.8	457.0	**(159.4)**	(57.2)
Interest and other income (loss)	**4.0**	2.1	3.9	**1.9**	(1.8)
Income from unconsolidated affiliates	**0.1**	0.2	0.1	**(0.1)**	0.1
Unrealized and realized gain (loss) on basis-only swaps	**-**	-	(189.6)	**-**	189.6
Interest expense	**(81.9)**	(78.5)	(63.9)	**(3.4)**	(14.6)
Income from Continuing Operations before Income Taxes	**162.6**	323.6	207.5	**(161.0)**	116.1
Income taxes	**(57.9)**	(119.7)	(72.6)	**61.8**	(47.1)
Net Income Attributable to QEP	**$ 104.7**	$ 203.9	$ 134.9	**$ (99.2)**	$ 69.0

Operating expenses per unit

The following table presents certain QEP Energy operating expenses on a per unit of production basis. QEP Energy total operating expenses (the sum of depreciation, depletion and amortization expense, lease operating expense, natural gas, oil and NGL transportation and other handling costs, general and administrative expense, and a portion of total QEP interest expense that is allocated to QEP Energy based on intercompany agreements and production taxes) per Mcfe of production increased 2% to $4.81 per Mcfe in 2011 versus $4.72 per Mcfe in 2010. For the year ended December 31, 2010, QEP Energy total operating costs per Mcfe decreased $0.14 per Mcfe, or 3% from 2009. Operating expenses per unit are summarized in the following table:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(per Mcfe)		
Depreciation, depletion and amortization	**$ 2.57**	$ 2.59	$ 2.71	**$ (0.02)**	$ (0.12)
Lease operating expense	**0.54**	0.56	0.67	**(0.02)**	(0.11)
Natural gas, oil and NGL transportation and other handling costs	**0.68**	0.55	0.47	**0.13**	0.08
General and administrative expense	**0.36**	0.34	0.36	**0.02**	(0.02)
Allocated interest expense	**0.30**	0.34	0.34	**(0.04)**	-
Production taxes	**0.36**	0.34	0.31	**0.02**	0.03
Total Operating Expenses	**$ 4.81**	$ 4.72	$ 4.86	**$ 0.09**	$ (0.14)

Depreciation, depletion and amortization (DD&A) expense per Mcfe decreased $0.02 in the year ended December 31, 2011 from the 2010 period. QEP Energy's DD&A expense increased $114.7 million during the year ended December 31, 2011 from the year ended

December 31, 2010. While QEP Energy's total DD&A increased in 2011, the lower per unit expense in 2011 was the result of booking NGL reserves associated with the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP's Pinedale production. In 2010, DD&A expense decreased by $0.12 per Mcfe compared to 2009 primarily as a result of increased proved reserves related to higher field-level natural gas and oil prices compared to the prior year.

Lease operating expense per Mcfe decreased $0.02 for the year ended December 31, 2011 from the 2010 period as the result of increased production volumes in lower cost areas. Growing production from new high-rate, low-operating cost wells in the Haynesville/Cotton Valley area and in the Pinedale Anticline, coupled with declining production from older higher cost areas, reduced average per Mcfe lease operating expense. Lease operating expense per Mcfe was 16% lower in 2010 compared to 2009, primarily due to higher production volumes combined with flat operating expenses.

QEP Energy's average production costs (lease operating expense) per Mcfe were 4% lower in the 2011 period compared to the 2010 period. The decrease was a result of growing production in lower cost operating areas such as Haynesville/Cotton Valley and Pinedale, coupled with declining production in higher cost areas, which more than offset the higher cost associated with operating the growing oil volumes in the Northern Region. QEP Energy's average production cost decreased $0.11 per Mcfe in 2010 due to higher production volumes and flat operating expenses. The following table presents average production cost, excluding production taxes for QEP Energy for QEP Energy by region on a per unit of production basis.

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(per Mcfe)		
Southern Region	**$ 0.50**	$ 0.55	$ 0.79	**$ (0.05)**	$ (0.24)
Northern Region	**0.58**	0.56	0.57	**0.02**	(0.01)
Average production cost	**0.54**	0.56	0.67	**(0.02)**	(0.11)

Natural gas, oil and NGL transportation and other handling costs per Mcfe were 24% higher in 2011 than in 2010, due primarily to processing costs associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale. Natural gas, oil and NGL transportation and other handling costs increased $0.08 per Mcfe in 2010 compared to 2009, due primarily to increased natural gas production and related transportation costs at the Haynesville/Cotton Valley area. See Note 1 to the consolidated financial statements, "Summary of Significant Accounting Policies," for a discussion of the recasting of transportation and other handling costs.

General and administrative (G&A) expense per Mcfe increased $0.02 per Mcfe during the year ended December 31, 2011, as the result of higher G&A expenses, which were primarily related to employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs, which were partially offset by increased production in 2011. G&A expenses per Mcfe were 6% lower in 2010 than 2009 as a result of increased production volumes partially offset by higher labor, benefits and stock-based compensation expenses in 2010.

Allocated interest expense per unit of production decreased $0.04 per Mcfe in the year ended December 31, 2011, primarily due to higher production volumes. Allocated interest expense per Mcfe of production was flat when comparing the year ended December 31, 2010 to 2009.

In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume-based. Accordingly, production taxes per Mcfe increased by $0.02 per Mcfe during the year ended December 31, 2011 because of higher field-level oil and NGL prices. In the 2010 period, production taxes increased by 10% over the 2009 period, as the result of higher natural gas, oil and NGL prices.

QEP Field Services

QEP Field Services, which provides gas gathering and processing services, generated net income of $154.5 million in the year ended December 31, 2011 compared to $91.1 million in 2010, a 70% increase. During the year ended December 31, 2010, net income increased $21.7 million from the $69.4 million in 2009. The increase in net income in both 2011 and 2010 was the result of higher gathering and processing margins and increased throughput volumes. Following is a summary of QEP Field Services' financial and operating results:

	For the year ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
			(in millions)		
Operating Income					
Revenues					
NGL sales	**$ 180.0**	$ 94.8	$ 71.9	**$ 85.2**	$ 22.9
Processing (fee based)	**53.7**	35.2	32.4	**18.5**	2.8
Other processing fees	**2.2**	-	0.2	**2.2**	(0.2)
Gathering	**161.1**	152.5	127.3	**8.6**	25.2
Other gathering	**68.5**	36.7	32.8	**31.8**	3.9
Total Revenues	**465.5**	319.2	264.6	**146.3**	54.6
Operating expenses					
Processing	**12.2**	11.9	10.3	**0.3**	1.6
Processing plant fuel and shrinkage	**49.2**	32.6	28.1	**16.6**	4.5
Gathering	**44.6**	37.6	36.6	**7.0**	1.0
Natural gas, oil and NGL transportation and other handling costs	**9.3**	-	-	**9.3**	-
General and administrative	**29.2**	31.6	25.0	**(2.4)**	6.6
Taxes other than income taxes	**6.1**	4.4	4.6	**1.7**	(0.2)
Depreciation, depletion and amortization	**55.7**	48.9	44.3	**6.8**	4.6
Total Operating Expenses	**206.3**	167.0	148.9	**39.3**	18.1
Net gain (loss) from asset sales	**-**	(1.6)	(0.1)	**1.6**	(1.5)
Operating Income	**259.2**	150.6	115.6	**108.6**	35.0
Interest and other income	**0.1**	0.1	(0.2)	**-**	0.3
Income from unconsolidated affiliates	**5.4**	2.8	2.6	**2.6**	0.2
Interest expense	**(13.6)**	(7.6)	(6.0)	**(6.0)**	(1.6)
Income from Continuing Operations before Income Taxes	**251.1**	145.9	112.0	**105.2**	33.9
Income taxes	**(93.4)**	(51.9)	(40.0)	**(41.5)**	(11.9)
Income from Continuing Operations	**157.7**	94.0	72.0	**63.7**	22.0
Net income attributable to noncontrolling interest	**(3.2)**	(2.9)	(2.6)	**(0.3)**	(0.3)
Net Income Attributable to QEP	**$ 154.5**	$ 91.1	$ 69.4	**$ 63.4**	$ 21.7

See "Gathering" and "Processing" sections, as appeared earlier, for a discussion of the changes in QEP Field Services comparative financial statements.

QEP Marketing

QEP Marketing, which markets affiliate and third-party natural gas and oil, and owns and operates a gas storage facility, generated net income from continuing operations of $8.4 million during 2011, compared with $6.7 million during 2010. The increase in 2011 was due to a $2.7 million increase in interest income and a 54% increase in marketing sales volumes, partially offset by a 5% decrease in marketing margins. QEP Marketing net income decreased 21% from the 2009 net income of $8.5 million. The 2010 decrease from 2009 was a result of lower marketing and storage margins due to an overall decrease in natural gas price volatility.

LIQUIDITY AND CAPITAL RESOURCES

QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities, borrowings under its credit facility and, periodically, proceeds from debt offerings and asset sales. The Company believes cash flow from operations and availability under its credit facility will be sufficient to fund the Company's planned capital expenditures and operating expenses for 2012. To the extent actual operating results differ from the Company's estimates, the Company's liquidity could be adversely affected.

Cash Flows from Operating Activities

Cash flows from operations are primarily affected by natural gas, oil and NGL production volumes and commodity prices (including the effects of settlements of the Company's derivative contracts) and by changes in working capital. QEP enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future gas, oil and NGL production for the next 12 to 24 months. However, in general, QEP plans to hedge approximately 50% of its forecasted production by the end of the first quarter of the current year. See "Commodity Derivative Impact" above.

Net cash provided by operating activities of continuing operations increased 30% in 2011 compared to 2010, due to higher noncash adjustments to net income and a lower use of cash from operating assets and liabilities in 2011 compared with the use of cash in the 2010 period. Noncash adjustments to net income consisted primarily of depreciation, depletion and amortization; noncash unrealized gains and losses on basis-only swaps; changes in deferred income taxes; and abandonment and impairment charges. Cash uses from operating assets and liabilities were higher in 2011 primarily due to increases in accounts receivable and inventories during 2011 compared to 2010. Net cash provided by continuing operating activities from continuing operations decreased in 2010 by $151.9 million from 2009. Cash sources from operating assets and liabilities were lower in 2010 primarily due to reductions in accounts receivable during 2009 and a decrease in current federal income taxes payable due to bonus depreciation. Net cash provided from continuing operating activities is presented below:

	Year Ended December 31,			Change	
	2011	2010	2009	**2011 vs. 2010**	2010 vs. 2009
		(in millions)			
Income from continuing operations	**$ 270.4**	$ 285.9	$ 215.4	$ (15.5)	$ 70.5
Noncash adjustments to net income	**1,050.9**	784.5	863.0	266.4	(78.5)
Changes in operating assets and liabilities	**(28.7)**	(72.9)	71.0	44.2	(143.9)
Net cash provided by operating activities of continuing operations	**$ 1,292.6**	$ 997.5	$ 1,149.4	$ 295.1	$ (151.9)

Cash Flows from Investing Activities

A comparison of capital expenditures for continuing operations during the years ended December 31, 2011, 2010 and 2009 and a forecast for calendar year 2012 are presented in the table below:

	Year Ended December 31,			
	2011	2010	2009	2012 Forecast
		(in millions)		
QEP Energy	**$ 1,338.8**	$ 1,215.8	$ 1,033.7	$ 1,280.0
QEP Field Services	**101.6**	268.2	71.8	170.0
QEP Marketing and other	**5.4**	1.9	1.4	-
Total accrued capital expenditures of continuing operations	**1,445.8**	1,485.9	1,106.9	1,450.0
Change in accruals	**(14.7)**	(16.9)	90.0	-
Total cash capital expenditures of continuing operations	**$ 1,431.1**	$ 1,469.0	$ 1,196.9	$ 1,450.0

QEP Energy capital investment during the year ended December 31, 2011 increased $126.1 million over the 2010 period due to an increase in the number of company-operated well completions as a result of ongoing efficiency gains, combined with acquisition of additional working interests in certain wells due to partner elections not to participate. QEP Energy capital expenditures were higher in 2010 compared to 2009 due to an increased drilling program in 2010.

QEP Field Services capital investment declined $166.6 million during the year ended December 31, 2011 compared to the 2010 period due to the completion of major capital projects in eastern Utah and northwest Louisiana in late 2010 and the completion of the Blacks Fork II plant early in the third quarter of 2011. QEP Field Services capital investment was higher in 2010 than 2009 due to increased investment in its gathering, processing and treating facilities to expand capacity in western Wyoming, eastern Utah and northwest Louisiana.

Cash Flows from Financing Activities

During the year ended December 31, 2011, net cash used in investing activities of $1,422.9 million exceeded net cash provided by operating activities of $1,292.6 million by $130.3 million. Net cash used in investing activities during 2010 also exceeded net cash provided by operating activities by $393.0 million, however, in 2009, net cash provided by operating activities of $1,149.4 million exceeded net cash used in investing activities of $1,146.4 million by $3.0 million. The reason that 2009 operating cash flows exceeded investing activities was a result of the economic downturn, in which the Company limited capital expenditures to approximate internally generated cash flow. For 2011, long-term debt increased by a net change of $207.1 million while short-term debt decreased by $58.5 million. At December 31, 2011, long-term debt consisted of $606.5 million outstanding under QEP's revolving credit facility and $1,072.9 million in senior notes (including $5.5 million of net original issue discount). At December 31, 2011, combined short-term and long-term debt was 33% and equity was 67% of total capital. All intercompany loans between Questar and QEP, which have been historically reported as notes payable in the Consolidated Balance Sheets, were repaid on June 30, 2010, in conjunction with the Spin-off.

Credit Facility

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016 and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The agreement also contains the provisions which would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for two additional one-year periods. QEP increased its borrowings under its credit facility from $400.0 million as of December 31, 2010, to $606.5 million as of December 31, 2011. QEP's weighted-average interest rate on borrowings from its credit facilities was 3.05%. Proceeds from borrowings under the credit facility were used to refinance outstanding amounts under the Company's previous credit facility and will be used for general corporate purposes, including working capital and capital expenditures. The credit agreement includes financial covenants (i) limiting the ratio of the consolidated funded debt of the Company to the sum of consolidated funded debt plus shareholders' equity to not more than 0.6 to 1, (ii) limiting the ratio of the consolidated funded debt of the Company to the Company's consolidated EBITDA to not more than 3.5 to 1, and (iii) if the Company's debt ratings fall below a certain level, limiting the Company' total consolidated funded debt to a specified aggregate amount. At December 31, 2011, QEP was in compliance with all of its debt covenants. At February 17, 2012, QEP had $614.0 million outstanding under its revolving credit facility and $4.1 million of letters of credit issued.

Senior Notes

The Company's senior notes outstanding as of December 31, 2011 totaled $1,078.4 million principal amount and are comprised of four issues as follows:

- $176.8 million 6.05% Senior Notes due September 2016
- $138.6 million 6.80% Senior Notes due April 2018
- $138.0 million 6.80% Senior Notes due March 2020
- $625.0 million 6.875% Senior Notes due March 2021

In August 2010, the Company purchased $638.0 million principal amount of its senior notes and paid required premium and accrued interest pursuant to the requirement in the notes' indenture relating to a change of control. The Company used cash on hand and proceeds from its $1.0 billion revolving credit facility and its $500.0 million term loan to purchase all of the tendered notes. Subsequent to the purchase of the tendered notes, the Company issued $625.0 million principal amount of senior notes due 2021. The notes were issued at a discount, resulting in gross proceeds of $619.2 million which were used to pay fees and expenses associated with the issuance and to refinance a portion of the indebtedness incurred under the term loan and revolving credit facilities to purchase the tendered senior notes. Upon repayment of the term loan, commitments under the term loan were terminated.

Capital Expenditures

During the year ended December 31, 2011, cash capital expenditures decreased 3% to $1,431.1 million, which included $48.0 million for property acquisitions, compared to $1,469.0 million during the same period in 2010. The decrease was driven by reduced development drilling in the Haynesville/Cotton Valley and Pinedale Anticline, partially offset by higher capital investment in development drilling in the Midcontinent and the Rockies Legacy divisions. Approximately $1,295.5 million was used in QEP Energy, including $1,247.5 million in drilling and completion and other expenditures and $48.0 million in property acquisition costs. QEP Field Services 2011 capital expenditures of $130.1 million were used to expand capacity at the Company's gathering, processing and treating facilities including the Blacks Fork II cryogenic gas processing plant which was completed in July of 2011. In 2010, capital expenditures were $272.1 million higher than in the comparable 2009 period. The increase in 2010 was driven by QEP Field Services and its increased investment in its gathering, processing and treating facilities to expand capacity in western Wyoming, eastern Utah and northwest Louisiana. Also contributing to the 2010 increase was QEP Energy's increased capital expenditures due to an increased drilling program in 2010.

In 2012, QEP intends to fund capital expenditures with cash flow from operating activities and borrowings under its revolving credit facility, if needed. As a result of the continued spread between oil and natural gas prices, in 2012 QEP plans to decrease capital expenditures for the Haynesville Shale and other dry gas development areas and increase capital expenditures for higher return projects, including Pinedale, the Bakken, and oil-directed horizontal drilling in the Powder River Basin and Midcontinent and continued development of QEP's Uinta Basin Red Wash liquids-rich gas play. QEP has allocated approximately 88% of its forecasted 2012 drilling and completion capital expenditure budget to oil and liquids-rich natural gas projects in its portfolio. The Company has budgeted approximately $1,450.0 million for capital expenditures in 2012, of which it has allocated $1,280.0 million to QEP Energy. QEP plans to invest approximately $170.0 million in capital expenditures to grow its midstream business, including construction of a new 150 MMcfpd fee-based cryogenic gas processing plant in the Uinta Basin. The aggregate levels of capital expenditures for 2012 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, natural gas and oil prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management's business assessments as to where QEP's capital can be most profitably deployed.

Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP's estimates.

Off-Balance Sheet Arrangements

QEP may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2011, the Company's material off-balance sheet arrangements and transactions included operating lease arrangements, drilling and transportation contracts and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect QEP's liquidity or availability of, or requirements for capital resources. *See* "Contractual Cash Obligations and Other Commitments" below for more information regarding off-balance sheet arrangements.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2011:

	Payments Due by Year						
	Total	2012	2013	2014	2015	2016	After 2016
				(in millions)			
Long-term debt [1]	$ 1,684.9	$ -	$ -	$ -	$ -	$ 783.3	$ 901.6
Interest on fixed-rate long-term debt [2]	579.4	72.5	72.5	72.5	72.5	68.9	220.5
Drilling contracts	146.2	70.8	37.2	36.1	2.1	-	-
Transportation contracts	406.8	45.4	44.3	43.3	43.2	41.8	188.8
Asset Retirement Obligations [3]	284.6	15.3	2.9	3.2	2.4	4.0	256.8
Operating leases	59.1	5.6	6.1	5.6	5.7	5.8	30.3
Total	$ 3,161.0	$ 209.6	$ 163.0	$ 160.7	$ 125.9	$ 903.8	$ 1,598.0

(1) Includes $606.5 milllion relating to the Company's revolving credit facility.

(2) Excludes variable rate debt interest payments relating to the Company's revolving credit facility.

(3) These future obligations are estimates of when the liabilities will be settled.

(4) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Item 8 of this annual report on Form 10-K, note 11 "Employee Benefits" for additional information.

Critical Accounting Policies, and Estimates

QEP's significant accounting policies are described in Note 1 to the consolidated financial statements included in Item 8 of Part II of its Annual Report. The Company's consolidated financial statements are prepared in accordance with U.S. Generally Accepted Accounting Principles. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following accounting policies may involve a higher degree of complexity and judgment on the part of management.

Gas and Oil Reserves

Gas and oil reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures.

Estimates of proved gas and oil reserves significantly affect the Company's DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause QEP to perform an impairment analysis to determine if the carrying amount of crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Successful Efforts Accounting for Gas and Oil Operations

The Company follows the successful efforts method of accounting for gas and oil property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, the delay rental and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred.

The capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized proved-property-acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploratory well and development costs are amortized similarly by field based on proved developed reserves. The calculation takes into consideration estimated future equipment dismantlement, surface restoration and property abandonment costs, net of estimated equipment-salvage values. Other property and equipment are generally depreciated using the straight-line method over estimated useful lives or the unit-of-production method for certain processing plants. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

QEP Energy engages an independent reservoir engineering consultant to prepare estimates of the proved gas and oil reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development drilling information becomes available.

Impairment of Oil and Gas Properties

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, an impairment of gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in gas and oil prices and changes in the utilization of midstream gathering and processing assets. If impairment is indicated, fair value is calculated using a discounted-cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices and operating costs. During the fourth quarter of 2011, QEP recorded an impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern Region and Southern Region. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices.

Asset Retirement Obligations

QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of QEP's asset retirement obligations (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. QEP's AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at QEP's credit-adjusted risk-free interest rate. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimate timing of abandonment.

Accounting for Derivative Contracts

The Company uses derivative contracts, typically fixed-price swaps and costless collars, to protect against a decline in the price it receives from its natural gas, oil and NGL production. Accounting rules for derivatives require marking these instruments to fair value at the balance sheet reporting date. The change in fair value is reported either in net income or AOCI depending on the structure of the derivative. The Company has historically structured the majority of its energy derivative instruments as cash flow hedges as defined in ASC 815 "Derivatives and Hedging." Changes in the fair value of cash flow hedges are recorded on the balance sheet and in AOCI until the underlying gas or oil is produced. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production. Changes in the fair value of derivative contracts that do not qualify for hedge accountings are included as part of operating income in the Consolidated Statement of Income.

As of December 31, 2011, QEP designated most of its natural gas, oil and NGL derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to AOCI. Effective January 1, 2012, the Company has elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges at December 31, 2011 and have elected to discontinue hedge accounting prospectively. Accordingly, changes in the fair value of commodity derivative contracts will be reported each quarter in earnings as unrealized gains (losses). See Part II, Item 8, footnote 1 "Summary of Significant Accounting Policies" of this Form 10-K for additional information.

Revenue Recognition

Revenues are recognized in the period that services are provided or products are delivered. QEP Energy uses the sales method of accounting whereby revenue is recognized for all gas, oil and NGL sold to purchasers. Revenues include estimates for the two most recent months using published commodity-price indexes and volumes supplied by field operators. A liability is recorded to the extent that QEP Energy has an imbalance in excess of its share of remaining reserves in an underlying property. QEP Marketing presents revenues on a gross revenue basis. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in prices.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change QEP's estimate of environmental remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental or other contingent matters and actual costs may vary significantly.

Benefit Plan Obligations

QEP has non-contributory defined-benefit pension plans, including both qualified and supplemental plans. QEP also provides certain health care and life insurance benefits for certain retired employees. Determination of the benefit obligations for QEP's defined-benefit pension and postretirement plans impacts the recorded amounts for such obligations on the Consolidated Balance Sheets and the amount of benefit expense recorded to the Consolidated Income Statement.

Accounting for pension and other postretirement benefit obligations involves many assumptions, the most significant of which are the discount rate used to measure the present value of plan benefit obligations, the expected long-term rates of return on plan assets, the rate of future increases in compensation levels of participating employees and the future level of health care costs.

Share-Based Compensation

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The use of this model requires significant judgment with respect to the risk-free interest rate, expected price volatility, expected dividend yield, and expected life.

Income Taxes

The amount of income taxes recorded by QEP requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. QEP has recognized deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. QEP routinely assesses the realizability of its deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. QEP routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the impact of tax audits, changes in legislation and resolution of pending or future tax matters.

Recent Accounting Developments

See Recent Accounting Developments in Note 1 of the footnotes to the consolidated financial statements, in Item 8, Part II of this annual report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP's primary market-risk exposure arises from changes in the market price for natural gas, oil and NGL, and to a lesser extent, volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. QEP Energy and QEP Marketing have long-term contracts for pipeline capacity and are obligated to pay for transportation services with no guarantee that QEP will be able to fully utilize the contractual capacity of these transportation commitments. If energy prices decline or increase significantly, revenues and cash flow may significantly decline or increase. In addition, a non-cash write-down of the Company's oil and gas properties may be required if future oil and natural gas commodity prices experience a sustained, significant decline. A sensitivity analysis of the Company's commodity price related derivative instruments to changes in the price of the underlying commodities is presented below.

Commodity Price Risk Management

QEP's subsidiaries use commodity price derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these same arrangements typically limit future gains from favorable price movements. The Company's risk management policies provide for the use of derivative instruments to manage this risk. The types of commodity derivative instruments utilized by the Company include fixed-price swaps, costless collars, and basis-only swaps. The volume of commodity derivative instruments utilized by the Company may vary from year-to-year. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements. The derivative instruments currently utilized by the Company do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2011, QEP held sale and purchase commodity price derivative contracts totaling 213.0 million MMBtu of natural gas, 2.0 million barrels of oil, and 53.9 million gallons of NGL. As of December 31, 2010, the QEP derivative contracts covered 247.5 million MMBtu of natural gas and 1.1 million barrels of oil. Changes in the fair value of derivative contracts from December 31, 2010 to December 31, 2011, are presented below:

	Cash Flow Hedges	Basis-Only Swaps	Total
		(in millions)	
Net fair value of gas and oil derivative contracts outstanding at Dec. 31, 2010	$ 356.2	$ (117.7)	$ 238.5
Contracts settled	(311.1)	117.7	(193.4)
Change in gas and oil prices on futures markets	214.7	-	214.7
Contracts added	136.1	-	136.1
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2011	**$ 395.9**	**$ -**	**$ 395.9**

A table of the net fair value of gas, oil, and NGL derivative contracts that are scheduled to settle over the next five years as of December 31, 2011, is shown below. Derivatives representing approximately 69% of the net fair value will settle in the next twelve months and will be reclassified from AOCI to the Consolidated Statements of Income:

	Cash Flow Hedges	Basis-Only Swaps	Total
		(in millions)	
Contracts maturing by December 31, 2012	$ 272.4	$ -	$ 272.4
Contracts maturing between January 1, 2013 and December 31, 2013	123.5	-	123.5
Contracts maturing between January 1, 2014 and December 31, 2014	-	-	-
Contracts maturing between January 1, 2015 and December 31, 2015	-	-	-
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2011	**$ 395.9**	**$ -**	**$ 395.9**

The following table shows the sensitivity of fair value of gas and oil derivative contracts and basis-only swaps to changes in the market price of gas and oil and basis differentials:

	December 31, 2011	December 31, 2010
	(in millions)	
Net fair value - asset (liability)	**$ 395.9**	$ 238.5
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%	**490.3**	356.2
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%	**301.4**	132.1

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $94.5 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $94.4 million. However, a gain or loss would eventually be substantially offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company's commodity derivative transactions, see Managements' Discussion and Analysis of Financial Condition and Results of Operations- Commodity Derivative's Impact under Part I, Item 2 and see Note 6 – Derivative Contracts under Part II, Item 8 of this Annual Report on Form 10-K.

Credit Risk

QEP requests credit support and, in some cases, financial guarantees, letters of credit or prepayment from companies that pose unfavorable credit risks. The Company's five largest customers accounted for 32%, and 27% in aggregate, of QEP revenues before elimination of intercompany transactions in 2011 and 2010, and their accounts were current at December 31, 2011. However, each of the five largest customers sales were below 10% of QEP revenues.

Interest-Rate Risk Management

The Company's ability to borrow and the rates quoted by lenders can be adversely affected by the illiquid credit markets as described in Item 1A. Risk Factors of Part I of this Annual Report on Form 10-K. The Company's credit facility has floating interest rates and as such, exposes QEP to interest rate risk. If interest rates were to increase 10% over their average 2011, 2010 and 2009 levels and at QEP's average level of borrowing for those years, QEP's annualized interest expense would increase by $1.3 million, $0.5 million and $0.3 million, respectively, or less than 2% of the Company's total interest expense in each year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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All other schedules are omitted because they are not applicable or the required information is shown in the consolidated financial statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
QEP Resources, Inc.

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of QEP Resources, 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.

As discussed in Note 1 to the consolidated financial statements, during 2009, the Company adopted a new accounting standard relating to the presentation of noncontrolling interests in consolidated subsidiaries and the Company adopted new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), QEP Resources, Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 24, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
QEP Resources, Inc.

We have audited QEP Resources, Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). QEP Resources, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, QEP Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of QEP Resources, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011, of QEP Resources, Inc. and our report dated February 24, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 24, 2012

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
REVENUES			
Natural gas sales	**$ 1,239.1**	$ 1,205.3	$ 1,187.2
Oil sales	**324.2**	198.1	141.3
NGL sales	**129.7**	47.9	22.5
Gathering, processing and other	**380.9**	251.3	218.4
Purchased gas and oil sales	**1,085.3**	598.0	441.8
Total Revenues	**3,159.2**	2,300.6	2,011.2
OPERATING EXPENSES			
Purchased gas and oil expense	**1,077.1**	589.3	427.8
Lease operating expense	**145.2**	125.0	125.5
Natural gas, oil and NGL transportation and other handling costs	**102.2**	54.2	38.7
Gathering, processing and other	**107.3**	83.2	76.2
General and administrative	**123.2**	107.2	91.7
Separation costs	**-**	13.5	-
Production and property taxes	**105.4**	82.5	62.9
Depreciation, depletion and amortization	**765.4**	643.4	559.1
Exploration expenses	**10.5**	23.0	25.0
Abandonment and impairment	**218.4**	46.1	20.3
Total Operating Expenses	**2,654.7**	1,767.4	1,427.2
Net gain from asset sales	**1.4**	12.1	1.5
OPERATING INCOME	**505.9**	545.3	585.5
Interest and other income (loss)	**4.1**	2.3	4.5
Income from unconsolidated affiliates	**5.5**	3.0	2.7
Unrealized and realized loss on basis-only swaps	**-**	-	(189.6)
Loss from early extinguishment of debt	**(0.7)**	(13.3)	-
Interest expense	**(90.0)**	(84.4)	(70.1)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**424.8**	452.9	333.0
Income taxes	**(154.4)**	(167.0)	(117.6)
INCOME FROM CONTINUING OPERATIONS	**270.4**	285.9	215.4
Discontinued operations, net of income tax	**-**	43.2	80.7
NET INCOME	**270.4**	329.1	296.1
Net income attributable to noncontrolling interest	**(3.2)**	(2.9)	(2.6)
NET INCOME ATTRIBUTABLE TO QEP	**$ 267.2**	$ 326.2	$ 293.5
Earnings Per Common Share Attributable to QEP			
Basic from continuing operations	**$ 1.51**	$ 1.61	$ 1.23
Basic from discontinued operations	**-**	0.25	0.46
Basic total	**$ 1.51**	$ 1.86	$ 1.69
Diluted from continuing operations	**$ 1.50**	$ 1.60	$ 1.21
Diluted from discontinued operations	**-**	0.24	0.46
Diluted total	**$ 1.50**	$ 1.84	$ 1.67
Weighted-average common shares outstanding			
Used in basic calculation	**176.5**	175.3	174.1
Used in diluted calculation	**178.4**	177.3	176.3

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
Net income	**$ 270.4**	$ 329.1	$ 296.1
Other comprehensive income (loss), net of tax:			
Gains (losses) on changes in unrealized fair value of derivatives designated as cash flow hedges [1]	**24.8**	136.7	(254.5)
Pension and other postretirement plans adjustments:			
Net unamortized gain (loss) incurred [2]	**(14.7)**	2.6	-
Prior service cost incurred [3]	**-**	(33.8)	-
Recognized prior service cost [4]	**3.5**	1.7	-
Total pension and other postretirement plans adjustments	**(11.2)**	(29.5)	-
Other comprehensive income	**13.6**	107.2	(254.5)
Comprehensive income	**284.0**	436.3	41.6
Comprehensive income attributable to noncontrolling interests	**(3.2)**	(2.9)	(2.6)
Comprehensive income attributable to QEP	**$ 280.8**	$ 433.4	$ 39.0

[1] Presented net of income tax expense of $14.7 million, and $81.0 million for the years ended December 31, 2011 and 2010 and net of income tax benefit of $150.6 million for the year ended December 31, 2009, respectively.

[2] Presented net of income tax benefit of $9.2 million for the year ended December 31, 2011, and net of income tax expense of $1.6 million for the year ended December 31, 2010, respectively.

[3] Presented net of income tax benefit of $20.9 million for the year ended December 31, 2010.

[4] Presented net of income tax expense of $2.1 million and $1.0 million for the years ended December 31, 2011 and 2010, respectively.

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ -	$ -
Accounts receivable, net	397.4	269.9
Fair value of derivative contracts	273.7	257.3
Inventories, at lower of average cost or market		
Gas, oil and NGL	16.2	16.4
Materials and supplies	87.6	65.4
Prepaid expenses and other	43.7	45.2
Total Current Assets	818.6	654.2
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	8,172.4	6,874.3
Unproved properties, not being depleted	326.8	322.0
Midstream field services	1,463.6	1,360.5
Marketing and other	49.8	44.5
Total Property, Plant and Equipment	10,012.6	8,601.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	3,339.2	2,454.4
Midstream field services	297.5	244.6
Marketing and other	14.6	12.3
Total Accumulated Depreciation, Depletion and Amortization	3,651.3	2,711.3
Net Property, Plant and Equipment	6,361.3	5,890.0
Investment in unconsolidated affiliates	42.2	44.5
Other Assets		
Goodwill	59.5	59.6
Fair value of derivative contracts	123.5	120.8
Other noncurrent assets	37.6	16.2
Total Other Assets	220.6	196.6
TOTAL ASSETS	$ 7,442.7	$ 6,785.3

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in millions)	
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 29.4**	$ 19.5
Accounts payable and accrued expenses	**457.3**	332.2
Production and property taxes	**40.0**	18.9
Interest payable	**24.4**	28.1
Fair value of derivative contracts	**1.3**	139.3
Deferred income taxes	**85.4**	27.8
Current portion of long-term debt	**-**	58.5
Total Current Liabilities	**637.8**	624.3
Long-term debt, less current portion	**1,679.4**	1,472.3
Deferred income taxes	**1,484.7**	1,377.7
Asset retirement obligations	**163.9**	148.3
Fair value of derivative contracts	**-**	0.3
Other long-term liabilities	**124.8**	99.3
Commitments and contingencies		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 177.2 million and 175.9 million shares issued at December 31, 2011 and 2010, respectively	**1.8**	1.8
Treasury stock - 0.4 million and 0.1 million shares at December 31, 2011 and 2010, respectively	**(13.1)**	(3.8)
Additional paid-in capital	**431.4**	398.0
Retained earnings	**2,673.5**	2,420.0
Accumulated other comprehensive income	**207.9**	194.3
Total Common Shareholders' Equity	**3,301.5**	3,010.3
Noncontrolling interest	**50.6**	52.8
Total Equity	**3,352.1**	3,063.1
TOTAL LIABILITIES AND EQUITY	**$ 7,442.7**	$ 6,785.3

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
					(in millions)				
Balances at December 31, 2008	173.6	$ 1.7	-	$ -	$ 144.5	$ 2,262.1	$ 341.6	$ 29.5	$ 2,779.4
Questar common stock issued, net of repurchases	1.0	-	-	-	-	-	-	-	-
2009 net income	-	-	-	-	-	293.5	-	2.6	296.1
Dividends paid	-	-	-	-	-	(17.4)	-	-	(17.4)
Share-based compensation	-	-	-	-	13.9	-	-	-	13.9
Consolidation of noncontrolling interest	-	-	-	-	(28.5)	-	-	28.5	-
Tax on equity adjustment	-	-	-	-	(3.1)	-	-	-	(3.1)
Distribution of noncontrolling interest	-	-	-	-	-	-	-	(5.7)	(5.7)
Change in unrealized fair value of derivatives, net of tax	-	-	-	-	-	-	(254.5)	-	(254.5)
Balances at December 31, 2009	174.6	1.7	-	-	126.8	2,538.2	87.1	54.9	2,808.7
Questar common stock issued, net of repurchases	0.4	-	-	-	-	-	-	-	-
2010 net income	-	-	-	-	-	326.2	-	2.9	329.1
Dividends paid	-	-	-	-	-	(15.9)			(15.9)
Share-based compensation	0.9	0.1	(0.1)	(3.9)	23.3	-	-	-	19.5
Equity from Questar		-	-	-	250.0	-	-	-	250.0
Transfer Wexpro to Questar	-	-	-	-	(2.0)	(428.5)	-	-	(430.5)
Distribution of noncontrolling interest	-	-	-	-	-	-	-	(5.0)	(5.0)
Change in unrealized fair value of derivatives, net of tax	-	-	-	-	-	-	136.7	-	136.7
Change in pension and postretirement liability, net of tax	-	-	-	-	-	-	(29.5)	-	(29.5)
Balances at December 31, 2010	175.9	1.8	(0.1)	(3.9)	398.1	2,420.0	194.3	52.8	3,063.1
2011 net income	**-**	**-**	**-**	**-**	**-**	**267.2**	**-**	**3.2**	**270.4**
Dividends paid	**-**	**-**	**-**	**-**	**-**	**(14.1)**	**-**	**-**	**(14.1)**
Share-based compensation	**1.3**	**-**	**(0.3)**	**(9.2)**	**33.3**	**-**	**-**	**-**	**24.1**
Distribution from Questar and other	**-**	**-**	**-**	**-**	**-**	**0.4**	**-**	**-**	**0.4**
Distribution of noncontrolling interest	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(5.4)**	**(5.4)**
Change in unrealized fair value of derivatives	**-**	**-**	**-**	**-**	**-**	**-**	**24.8**	**-**	**24.8**
Change in pension and postretirement liability, net of tax							**(11.2)**	**-**	**(11.2)**
Balances at December 31, 2011	**177.2**	**$ 1.8**	**(0.4)**	**$ (13.1)**	**$ 431.4**	**$ 2,673.5**	**$ 207.9**	**$ 50.6**	**$ 3,352.1**

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
	(in millions)		
OPERATING ACTIVITIES			
Net income	**$ 270.4**	$ 329.1	$ 296.1
Discontinued operations, net of income tax	**-**	(43.2)	(80.7)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**765.4**	643.4	559.1
Deferred income taxes	**156.8**	188.2	103.3
Abandonment and impairment	**218.4**	46.1	20.3
Share-based compensation	**22.0**	16.1	13.4
Amortization of debt issuance costs and discounts	**4.1**	2.4	1.2
Dry exploratory well expense	**0.3**	9.6	4.7
Net gain from asset sales	**(1.4)**	(12.1)	(1.5)
Income from unconsolidated affiliates	**(5.5)**	(3.0)	(2.7)
Distributions from unconsolidated affiliates and other	**7.8**	2.2	1.2
Loss on early extinguishment of debt	**0.7**	13.3	-
Unrealized (gain) loss on basis-only swaps	**(117.7)**	(121.7)	164.0
Changes in operating assets and liabilities			
Accounts receivable	**(144.6)**	(32.6)	42.6
Inventories	**(22.0)**	10.1	13.7
Prepaid expenses	**1.6**	(16.2)	(3.1)
Accounts payable and accrued expenses	**127.8**	4.2	9.9
Federal income taxes	**17.0**	(30.9)	21.2
Other	**(8.5)**	(7.5)	(13.3)
Net Cash Provided by Operating Activities of Continuing Operations	**1,292.6**	997.5	1,149.4
INVESTING ACTIVITIES			
Property acquisitions	**(48.0)**	(109.3)	(221.5)
Property, plant and equipment, including dry exploratory well expense	**(1,383.1)**	(1,359.7)	(975.4)
Other investments	**-**	-	(1.5)
Proceeds from disposition of assets	**8.2**	25.6	14.2
Change in notes receivable	**-**	52.9	37.8
Net Cash Used in Investing Activities of Continuing Operations	**(1,422.9)**	(1,390.5)	(1,146.4)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**9.9**	19.5	-
Long-term debt issued	**591.5**	1,034.4	424.5
Long-term debt issuance costs paid	**(10.6)**	(16.6)	(2.5)
Current portion long-term debt repaid	**(58.5)**	(91.5)	-
Repayments of notes payable	**-**	(39.3)	(50.1)
Long-term debt repaid	**(385.0)**	(761.5)	(375.0)
Long-term debt extinguishment costs	**-**	(4.9)	-
Other capital contributions	**2.3**	2.8	-
Equity contribution	**-**	250.0	-
Dividends paid	**(14.1)**	(7.0)	-
Distribution from Questar	**0.2**	(7.2)	-
Distribution to noncontrolling interest	**(5.4)**	(5.0)	(5.7)
Net Cash Provided by Financing Activities of Continuing Operations	**130.3**	373.7	(8.8)
CASH USED IN CONTINUING OPERATIONS	**-**	(19.3)	(5.8)
Cash provided by operating activities of discontinued operations	**-**	68.6	174.4
Cash used in investing activities of discontinued operations	**-**	(39.9)	(116.2)
Cash used in financing activities of discontinued operations	**-**	(26.9)	(53.4)
Effect of change in cash and cash equivalents of discontinued operations	**-**	(1.8)	(4.8)
Change in cash and cash equivalents	**-**	(19.3)	(5.8)
Beginning cash and cash equivalents	**-**	19.3	25.1
Ending cash and cash equivalents	**$ -**	$ -	$ 19.3
Supplemental Disclosure of Cash Paid (Received) During the Year for:			
Interest	**$ 93.5**	$ 83.3	$ 62.2
Income taxes	**(28.5)**	14.0	(10.0)

See notes accompanying the consolidated financial statements.

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with three major lines of business – gas and oil exploration and production, midstream field services, and energy marketing – which are conducted through its three principal subsidiaries:

- QEP Energy Company, (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and natural gas liquids (NGL);
- QEP Field Services Company (QEP Field Services) provides midstream field services including natural gas gathering and processing, compressing and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Operations are focused in the Northern (formerly Rocky Mountain) and Southern (formerly Midcontinent) Regions of the United States. Company headquarters are in Denver, Colorado. Shares of QEP common stock trade on the New York Stock Exchange (NYSE:QEP).

Principles of Consolidation

The consolidated financial statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The consolidated financial statements were prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) and with the instructions for annual reports on Form 10-K and Regulations S-X and S-K. All significant intercompany accounts and transactions have been eliminated in consolidation.

On January 1, 2009, QEP adopted "Noncontrolling Interests in Consolidated Financial Statements" (ASC 810-10-65-1) for the accounting, reporting and disclosure of noncontrolling interests. The new guidance requires that noncontrolling interest, previously known as minority interest, be clearly identified, labeled, and presented in the consolidated financial statements separate from the parent's equity; the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented in the consolidated income statement; changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently; and any retained noncontrolling equity investment in a former subsidiary be initially measured at fair value. The new provisions are applied prospectively from the date of adoption, except for the presentation and disclosure requirements, which are applied retrospectively for all periods presented.

Effective May 18, 2010, Questar Market Resources, Inc., (Market Resources) then a wholly owned subsidiary of Questar Corporation (Questar), merged with and into a newly-formed, wholly owned subsidiary, QEP, a Delaware corporation in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. The Reincorporation Merger was approved by the boards of directors of Market Resources and QEP and submitted to a vote of, and approved by, the Board of Directors of Questar, as sole shareholder of Market Resources, and by Market Resources, as sole shareholder of QEP on May 18, 2010.

On June 30, 2010, Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spin-off). Each Questar shareholder received one share of QEP common stock for each one share of Questar common stock held (including fractional shares) at the close of business on the record date. In connection therewith, QEP distributed Wexpro Company (Wexpro), a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

The financial information presented in this Annual Report on Form 10-K presents QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 2 to the consolidated financial statements.

All dollar and share amounts in this Form 10-K are in millions, except per-share information and where otherwise noted.

SEC's Modernization of Oil and Gas Reporting Requirements

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X. The goal of Release No. 33-8995 was to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The most significant amendments affecting the Company include the following: (i) economic producibility of reserves and discounted cash flows are to be based on the arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless contractual arrangements designate the price to be used; and (ii) reserves may be estimated and categorized through the use of reliable technologies. Release No. 33-8995 is effective for financial statements for fiscal years ending on or after December 31, 2009.

Investment in Unconsolidated Affiliates

QEP uses the equity method to account for investment in unconsolidated affiliates where it does not have control, but has significant influence. Generally, the investment in unconsolidated affiliates on the Company's consolidated balance sheets equals the Company's proportionate share of equity reported by the unconsolidated affiliates. Investment is assessed for possible impairment when events indicate that the fair value of the investment may be below the Company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in the determination of net income.

The principal unconsolidated affiliates and QEP's ownership percentage as of December 31, 2011 and 2010, were Uintah Basin Field Services, LLC, (38%) and Three Rivers Gathering, LLC, (50%), both limited liability companies engaged in gathering and compressing natural gas.

Use of Estimates

The preparation of the consolidated financial statements and notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets and liabilities, and the disclosure of contingent assets and liabilities. The Company also incorporates estimates of proved developed and proved natural gas, oil and NGL reserves in the calculation of depreciation, depletion and amortization rates of its gas and oil properties. Changes in estimated quantities of its reserves could impact the Company's reported financial results as well as disclosures regarding the quantities and value of proved gas and oil reserves. Actual results could differ from these estimates.

Revenue Recognition

QEP subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues reflect the impact of price-hedging instruments. Revenues associated with the sale of natural gas and oil are accounted for using the sales method, whereby revenue is recognized as gas and oil is sold to purchasers. A liability is recorded to the extent that the Company has sold volumes in excess of its share of remaining gas and oil reserves in an underlying property. QEP's imbalance obligations at December 31, 2011 and 2010 were $4.9 million and $4.4 million, respectively.

QEP Marketing reports revenues on a gross basis because, in the judgment of management, the nature and circumstances of its marketing transactions are consistent with guidance for gross revenue reporting. QEP Marketing markets affiliate and third-party natural gas, oil and NGL volumes. QEP Marketing uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. QEP Marketing has not engaged in buy/sell arrangements, as described in ASC 845-10-25-4 "Accounting for Purchases and Sales of Inventory with the Same Counterparty."

Regulation of Underground Storage

QEP through Clear Creek Storage Company, LLC, operates an underground gas-storage facility under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The FERC establishes rates for the storage of natural gas. The FERC also regulates, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment.

Cash and Cash Equivalents

Cash equivalents consist principally of repurchase agreements with maturities of three months or less. In almost all cases, the repurchase agreements are highly liquid investments in overnight securities made through commercial-bank accounts that result in available funds the next business day.

Notes Receivable from or Payable to Questar Corporation

Prior to the Spin-off, Questar centrally managed cash. Notes receivable from or payable to Questar represented interest bearing demand notes for cash loaned to or borrowed from Questar until needed for operations. Amounts loaned to Questar earned an interest rate that was identical to the interest rate paid by the Company for borrowings from Questar. All intercompany loans between Questar and QEP were repaid on June 30, 2010, in conjunction with the Spin-off.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. Maintenance and repair costs are expensed as incurred with the exception of compressor maintenance costs, which are capitalized and depreciated. Significant accounting policies for our property, plant and equipment are as follows:

Gas and oil properties

QEP Energy uses the successful efforts method to account for gas and oil properties. The costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, purchasing related support equipment and facilities are capitalized. Geological and geophysical studies and other exploratory activities are expensed as incurred. Costs of production and general-corporate activities are expensed in the period incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production depreciation, depletion and amortization rate would be significantly affected.

Capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned. QEP Energy proved and unproved leaseholds had a net book value of $1,035.7 million at December 31, 2011, and $1,130.5 million at December 31, 2010.

Capitalized exploratory well costs

The Company capitalizes exploratory well costs until it determines whether an exploratory well is commercial or noncommercial. If the Company deems the well commercial, capitalized costs are depreciated on a field basis using the unit-of-production method, and the estimated proved developed gas and oil reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory-well costs capitalized for a period greater than one year since the completion of drilling are expensed unless the Company remains engaged in substantial activities to assess whether the well is commercial.

Depreciation, depletion and amortization

Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated proved gas and oil reserves. Oil and NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil, condensate or NGL to 6,000 cubic feet of natural gas. Capitalized costs of exploratory wells that have found proved gas and oil reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves on a field basis. The Company capitalizes an estimate of the fair value of future abandonment costs. Future abandonment costs, less estimated future salvage values, are depreciated over the life of the related asset using a unit-of-production method.

Depreciation, depletion and amortization for the remaining Company properties is based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using either a straight-line or unit-of-production method. Investment in gas gathering and processing fixed assets is charged to expense using either the straight-line or unit-of-production method depending upon the facility. The estimated useful lives of those assets depreciated under the straight-line basis generally range as follows:

Buildings	10 years to 30 years
Leasehold improvements	3 years to 10 years
Service, transportation and field service equipment	3 years to 7 years
Furniture and office equipment	3 years to 7 years

Impairment of Long-Lived Assets

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, an impairment of gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in gas and oil prices and changes in the utilization of midstream gathering and processing assets. If impairment is indicated, fair value is calculated using a discounted-cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of probable and possible reserves. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the fourth quarter of 2011, QEP recorded a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair values. Of the $195.2 million impairment charge, $163.5 million were related to properties in the Northern Region with the remaining $31.7 million related to properties in the Southern Region.

The Company also performs periodic assessments of individually significant unproved gas and oil properties for impairment and recognizes a loss at the time of impairment. In determining whether a significant unproved property is impaired the Company considers numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluations of the lease, and the remaining lease term.

Asset Retirement Obligations

Asset retirement obligations (AROs) associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement costs, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of AROs change, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Capitalized Interest

The Company capitalizes interest costs during the construction phase of large capital projects that meet certain criteria. Capitalized interest was $3.0 million in 2011 and $3.1 million in 2010. There was no capitalized interest during 2009.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the amount paid over the fair value of net assets acquired in a business combination and is not subject to amortization. Goodwill and indefinite-lived intangible assets are tested for impairment at a minimum of once a year or when a triggering event occurs. If a triggering event occurs, the undiscounted net cash flows of the intangible asset or entity to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted-cash flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors.

Derivative Instruments

The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value or cash flows. If the hedged exposure is a fair value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting gain or loss from the change in fair value of the hedged item. If the hedged exposure is a cash flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of AOCI and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in the current period income statement. A derivative instrument qualifies as a cash flow hedge if all of the following tests are met:

- The item to be hedged exposes the Company to price risk.
- The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.
- At the inception of the hedge and throughout the hedge period, there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying hedged item.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are included in income in the same period that the underlying production or other contractual commitment is delivered. When a derivative instrument is associated with an anticipated transaction that is no longer probable, the gain or loss on the derivative is reclassified from other comprehensive income and recognized currently in the results of operations. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

As of December 31, 2011, QEP designated most of its natural gas, oil and NGL derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to AOCI. Effective January 1, 2012, the Company has elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges and has elected to discontinue hedge accounting prospectively.

As a result, subsequent to December 31, 2011, QEP will recognize all gains and losses from prospective changes in natural gas, oil and NGL derivative fair values immediately in earnings rather than deferring any such amounts in AOCI. At December 31, 2011, AOCI consisted of $395.9 million ($248.6 million after tax) of unrealized gains, representing the mark-to-market value of the Company's cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2012, such mark-to-market values at December 31, 2011 are frozen in AOCI as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions occur and effect earnings. QEP expects to reclassify into earnings from AOCI the frozen value related to de-designated natural gas, oil and NGL hedges during 2012 and 2013.

Physical Contracts

Physical hedge contracts have a nominal quantity and a fixed price. Contracts representing both purchases and sales settle monthly based on quantities valued at a fixed price. Purchase contracts fix the purchase price paid and are recorded as cost of sales in the month the contracts are settled. Sales contracts fix the sales price received and are recorded as revenues in the month they are settled. Due to the nature of the physical market, there is a one-month delay for the cash settlement. QEP accrues for the settlement of contracts in the current month's revenues and cost of sales.

Financial Contracts

Financial contracts are contracts that are net settled in cash without delivery of product. Financial contracts also have a nominal quantity and exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. Financial contracts are recorded in revenues or cost of sales in the month of settlement.

Basis-Only Swaps

Basis-only swaps are used to manage the risk of widening basis differentials. These contracts are marked to market monthly with any change in the valuation recognized in the determination of income.

Credit Risk

The Rocky Mountain and Midcontinent regions constitute the Company's primary market areas. Exposure to credit risk may be affected by the concentration of customers in these regions due to changes in economic or other conditions. Customers include individuals and numerous commercial and industrial enterprises that may react differently to changing conditions. Management believes that its credit-review procedures, loss reserves, customer deposits and collection procedures have adequately provided for usual and customary credit-related losses. Commodity-based hedging arrangements also expose the Company to credit risk. The Company monitors the creditworthiness of its counterparties, which generally are major financial institutions and energy companies. Loss reserves are periodically reviewed for adequacy and may be established on a specific case basis. QEP requests credit support and, in some cases, fungible collateral from companies with unacceptable credit risks. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Bad debt expense associated with accounts receivable for the year ended December 31, 2011 and 2009 was $0.2 million and $0.4 million compared with a credit of $0.3 million in 2010. The allowance for bad-debt expenses was $1.7 million at December 31, 2011, and $2.3 million at December 31, 2010.

Income Taxes

Prior to the Spin-off, Questar and its subsidiaries filed consolidated federal income tax returns. QEP accounts for income tax expense on a separate-return basis and records tax benefits as they are generated. Deferred income taxes are provided for the temporary differences arising between the book and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. The Company records interest earned on income tax refunds in interest and other income and records penalties and interest charged on tax deficiencies in interest expense.

ASC 740 "Income Taxes" specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized. There were no unrecognized tax benefits at the beginning or at the end of the twelve-month periods ended December 31, 2011, 2010 and 2009. The federal income tax returns for 2010 and 2009 are currently under examination by the Internal Revenue Service. Income tax returns for 2011 have not yet been filed. Most state tax returns for 2008 and subsequent years remain subject to examination.

Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income attributable to QEP by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in the money stock options. During the first quarter of 2009, the Company adopted the updated provisions of ASC 260, "Earnings Per Share." ASC 260 addresses whether instruments granted in share-based payment transactions are participating securities and therefore have a potential dilutive effect on EPS. The adoption was applied retrospectively and did not have a material effect on the Company's EPS calculations.

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company's unvested restricted stock awards contain nonforfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, the two-class method will not have an effect on the Company's basic earnings per share. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings per common share. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2011	2010	2010
		(in millions)	
Weighted-average basic common shares outstanding	**176.5**	175.3	174.1
Potential number of shares issuable under the Long-term Stock Incentive Plan	**1.9**	2.0	2.2
Average diluted common shares outstanding	**178.4**	177.3	176.3

Share-Based Compensation

QEP issued stock options and restricted shares to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The granting of restricted shares results in recognition of compensation cost measured at the grant-date market price. QEP uses an accelerated method in recognizing share-based compensation costs with graded-vesting periods. Stock options for participants have terms ranging from five to ten years with a majority issued with a seven year term. Options held by employees generally vest in three or four equal, annual installments. Restricted shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three or four years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. At the time of the Spin-off, all outstanding options and restricted stock were bifurcated. For a summary of LTSIP transactions see Note 10—Share-Based Compensation.

Pension Plans, Other Postretirement Benefits and Defined-Contribution Plans

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected rate of return on plan assets (for funded pension plans), the rate of future compensation increases and the health care cost trend rate. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually.

Environmental Contingencies

Except for environmental contingencies acquired in a business combination, which are recorded at fair value, QEP accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

Comprehensive Income

Comprehensive income is the sum of net income attributable to QEP as reported in the Consolidated Statements of Income and changes in the components of other comprehensive income. Other comprehensive income includes certain items that are recorded directly to equity and classified as accumulated other comprehensive income (AOCI). One component of other comprehensive income is changes in the market value of commodity-based derivative instruments that qualify for hedge accounting. Income or loss associated with commodity-based derivative instruments that qualify for hedge accounting is realized when the natural gas, oil or NGL underlying the derivative instrument is sold. Comprehensive income also includes changes in the under-funded portion of the defined benefit pension plans and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions are not the culmination of the earnings process but result from periodically adjusting historical balances to fair value.

Business Segments

Line of business information is presented according to senior management's basis for evaluating performance considering differences in the nature of products, services and regulation.

Transportation and other handling costs

During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs to appropriately reflect revenues in accordance with GAAP and industry practice. Transportation and handling costs, previously netted against revenues, have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. The impact of this revision is immaterial to the accompanying financial statements and has no effect on net income.

Recent Accounting Developments

In September of 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-08, which amends the guidance on testing goodwill for impairment. The new guidance provides entities that are testing goodwill the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If, according to a qualitative assessment, the carrying value of the reporting unit is more likely than not less than the fair value, further impairment testing is not required. However, if the qualitative assessment does not provide such conclusive evidence, further testing and calculation of fair value of the reporting unit will be required. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU did not have a material impact on the financial statements of QEP.

In June of 2011, the FASB issued ASU 2011-05, which revises the manner in which entities are able to present the components of comprehensive income in their financial statements. The new guidance requires entities to report the components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. However, this ASU does not change the items that are reported in other comprehensive income. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU required minor disclosure changes to QEP's financial statements and footnotes.

In May of 2011, the FASB issued ASU 2011-04, which provides converged guidance on how to measure fair value and requires additional disclosures relating to fair value measurements. Most of the amendments created by this ASU are to bridge the gap between GAAP and International Financial Reporting Standards. However some of the amendments may change how the current fair value measurement guidance is applied. In addition, the ASU expands the qualitative and quantitative fair value disclosure requirements, with most of these additional disclosures pertaining to Level 3 measurements. The amendments are effective for reporting periods (including interim periods) beginning after December 15, 2011. The adoption of this ASU did not have a material impact on QEP's financial statements or disclosures.

In December 2011, the FASB issued ASU 2011-11, which enhances disclosure requirements regarding an entity's financial instruments and derivative instruments that are offset or subject to master netting arrangement. This information about offsetting and related netting arrangements will enable users of financial statements to understand the effect of those arrangements on the entity's financial position, including the effect of rights of setoff. The amendments are required for annual reporting periods beginning after January 1, 2013 and interim periods within those annual periods. QEP is evaluating the impact of this ASU on its disclosure requirements.

Note 2 – Discontinued Operations

Wexpro's operating results prior to the Spin-off are reflected in this Annual Report on Form 10-K as discontinued operations and summarized below:

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
Revenues	$ -	$ 131.2	$ 242.9
Income before income taxes	-	67.4	126.9
Income taxes	-	(24.2)	(46.2)
Discontinued operations, net of income taxes	$ -	$ 43.2	$ 80.7
Earnings per common share attributable to QEP			
Basic from discontinued operations	$ -	$ 0.25	$ 0.46
Diluted from discontinued operations	-	0.24	0.46

Note 3 – Asset Retirement Obligations

QEP records asset retirement obligations (ARO) when there are legal obligations associated with the retirement of tangible long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with gas and oil wells, production facilities and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar properties and depreciated over the life of the related assets. Revisions to ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Income or expense resulting from the settlement of ARO liabilities is included in net gain or (loss) from asset sales in the Consolidated Statements of Income. Changes in ARO were as follows:

	2011	2010
	(in millions)	
ARO liability at January 1,	$ 148.3	$ 124.7
Accretion	9.7	8.8
Liabilities incurred	7.9	17.0
Liabilities settled	(2.0)	(2.2)
ARO liability at December 31,	$ 163.9	$ 148.3

Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below and exclude amounts that were capitalized and subsequently expensed in the period. All of these costs have been capitalized for less than one year after the completion of drilling.

	2011	2010	2009
		(in millions)	
Balance at January 1,	$13.6	$51.7	$17.0
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	12.2	51.7
Reclassifications to property, plant and equipment after the determination of proved reserves	(8.3)	(50.3)	(14.3)
Capitalized exploratory well costs charged to expense	(0.3)	-	(2.7)
Balance at December 31,	$ 5.0	$13.6	$51.7

Note 5—Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820 "Fair Value Measurements and Disclosures." This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements, but does not change existing guidance as to whether or not an instrument is carried at fair value. ASC 820 also establishes a fair-value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. QEP's Level 2 fair value measurements consist of fixed-price swaps of natural gas, oil and NGL. Level 3 inputs are unobservable inputs for the asset or liability. QEP's Level 3 measurements are made up of costless collars for natural gas and oil. The Level 2 fair value of derivative contracts (see Note 6) is based on market prices posted on the NYMEX on the last trading day of the reporting period and industry-standard discounted cash flow models. The Level 3 fair value of derivative contracts is based on NYMEX market prices in combination with unobservable volatility inputs and industry-standard option pricing models.

QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique.

Certain of QEP's derivative instruments, however, are valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with a counterparty exists.

QEP did not have any assets or liabilities measured at fair value on a non-recurring basis, other than ARO's, at December 31, 2011 and 2010. The fair values of assets and liabilities at December 31, 2011, are shown in the table below:

	Fair Value Measurements December 31, 2011							
	Level 2		Level 3		Netting Adjustments		Total	
	(in millions)							
Assets								
Derivative contracts - short term	$	**284.1**	$	**-**	$	**(10.4)**	$	**273.7**
Derivative contracts - long term		**123.5**		**-**		**-**		**123.5**
Total assets	$	**407.6**	$	**-**	$	**(10.4)**	$	**397.2**
Liabilities								
Derivative contracts - short term	$	**11.7**	$	**-**	$	**(10.4)**	$	**1.3**
Derivative contracts - long term		**-**		**-**		**-**		**-**
Total liabilities	$	**11.7**	$	**-**	$	**(10.4)**	$	**1.3**

The fair values of assets and liabilities at December 31, 2010, are shown in the table below:

	Fair Value Measurements December 31, 2010							
	Level 2		Level 3		Netting Adjustments		Total	
	(in millions)							
Assets								
Derivative contracts - short term	$	374.6	$	37.9	$	(155.2)	$	257.3
Derivative contracts - long term		121.1		-		(0.3)		120.8
Total assets	$	495.7	$	37.9	$	(155.5)	$	378.1
Liabilities								
Derivative contracts - short term	$	292.9	$	1.6	$	(155.2)	$	139.3
Derivative contracts - long term		0.6		-		(0.3)		0.3
Total liabilities	$	293.5	$	1.6	$	(155.5)	$	139.6

The change in the fair value of Level 3 assets and liabilities is shown below:

	Change in Level 3 Fair Value Measurements			
	2011		2010	
	(in millions)			
Balance at January 1,	$	**36.3**	$	5.5
Realized gains and losses included in revenues		**25.3**		5.0
Unrealized gains and losses included in other comprehensive income		**(36.3)**		30.8
Settlements		**(25.3)**		(5.0)
Balance at December 31,	$	**-**	$	36.3

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other notes to the Consolidated Financial Statements in this annual report on Form 10-K:

	Carrying Amount		**Estimated Fair Value**		Carrying Amount		Estimated Fair Value	
	December 31, 2011				December 31, 2010			
	(in millions)							
Financial assets								
Cash and cash equivalents	$	**-**	$	**-**	$	-	$	-
Financial liabilities								
Checks outstanding in excess of cash balances		**29.4**		**29.4**		19.5		19.5
Long-term debt		**1,679.4**		**1,754.9**		1,530.8		1,575.8

The carrying amounts of cash and cash equivalents, and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the year. The carrying amount of variable-rate long-term debt approximates fair value.

Note 6 – Derivative Contracts

QEP uses commodity price derivative instruments in the normal course of business. QEP has established policies and procedures for managing commodity price risks through the use of derivative instruments. QEP uses derivative instruments to reduce the impact of downward movements in commodity prices on cash flow, returns on capital, and other financial results. However, these instruments typically limit future gains from favorable price movements. The volume of production subject to derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into derivative contracts for up to 100% of forecasted production from proved reserves. QEP does not enter into derivative instruments for speculative purposes.

QEP uses derivative instruments known as fixed-price swaps and costless collars to realize a known price or range of prices for a specific volume of production delivered into a regional sales point. Costless collars are combinations of put and call options that have a floor price and a ceiling price and payments are made or received only if the settlement price is outside the range between the floor and ceiling prices. QEP's derivative instruments do not require the physical delivery of natural gas, crude oil, or NGL between the parties at settlement. Swap and costless collar transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. In the past, QEP Energy has used natural gas basis-only swaps to protect cash flow, project returns, and other financial results from widening natural gas price basis differentials. As of December 31, 2009, all of the Company's natural gas basis-only swaps had been paired with NYMEX gas fixed-price swaps or costless collars and re-designated as cash flow hedges.

QEP generally enters into derivative instruments that do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. Derivative contract counterparties are normally financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties and by transacting with multiple counterparties.

All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at their fair values. Reported changes in the fair value of derivatives depend upon whether the derivative instrument qualifies for hedge accounting. A derivative instrument qualifies for hedge accounting if, at inception, the derivative is expected to be highly effective in offsetting the underlying unhedged cash flows. Generally, QEP's derivative instruments are matched to company-owned natural gas, oil and NGL production and are therefore highly effective, thus qualifying as cash flow hedges. Changes in the fair value of effective cash flow hedges are recorded as a component of AOCI in the Consolidated Balance Sheets and reclassified to earnings as natural gas, oil and NGL sales when the underlying contract is settled. Natural gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Oil hedges are typically structured as NYMEX Calendar fixed-price swaps based at Cushing, Oklahoma. Oil fixed-price swaps inherently contain ineffectiveness because physical sales are priced at the purchaser's published regional prices. NGL hedges are typically structured as Mont Belvieu, Texas fixed-price swaps. Since most of our NGL sales are also based upon Mont Belvieu prices, there is no ineffectiveness. Costless collars qualify for cash flow hedge accounting. Basis-only swaps do not qualify for hedge accounting treatment. Changes in the fair value of these derivative instruments subsequent to their re-designation were recorded in AOCI, while changes in their fair value occurring prior to their re-designation were recorded in the Consolidated Statements of Income. QEP regularly reviews the effectiveness of derivative instruments. The ineffective portion of cash flow hedges and the mark-to-market adjustment in the value of basis-only swaps are recognized in the determination of net income. The effects of derivative transactions are summarized in the tables below:

	Year Ended December 31,		
	2011	2010	2009
	(in millions)		
Effect of derivative instruments designated as cash flow hedges			
Gains (losses) recognized in AOCI for the effective portion of hedges	**$ 350.8**	$ 565.8	$ 214.4
Gains (losses) reclassified from AOCI into income for the effective portion of hedges			
Natural gas sales	**305.5**	353.8	599.3
Oil sales	**1.6**	(8.7)	1.6
Gathering, processing and other	**(0.2)**	-	-
Purchased gas and oil sales	**-**	-	27.8
Purchased gas and oil expense	**4.3**	3.1	(9.2)
Income (loss) recognized in income for the ineffective portion of hedges			
Interest and other income (loss)	**0.1**	0.2	(0.1)
Effect of derivative instruments not designated as hedges			
Unrealized gain (loss) on basis-only swaps	**117.7**	121.7	(164.0)
Realized (loss) gain on basis-only swaps	**(117.7)**	(121.7)	(25.6)

Based on prices as of December 31, 2011, it is estimated that $171.1 million will be settled and reclassified from AOCI to the Consolidated Statements of Income during the next twelve months. The following table discloses the fair value of derivative contracts on a gross contract basis as opposed to the net contract basis presentation in the Consolidated Balance Sheets.

	December 31,	
	2011	2010
	(in millions)	
Assets		
Fixed-price swaps	**$ 284.1**	$ 374.6
Costless collars	**-**	37.9
Fair value of derivative instruments - short term	**$ 284.1**	$ 412.5
Fixed-price swaps	**$ 123.5**	$ 121.1
Costless collars	**-**	-
Fair value of derivative instruments - long-term	**$ 123.5**	$ 121.1
Liabilities		
Fixed-price swaps	**$ 11.7**	$ 175.2
Costless collars	**-**	1.6
Basis-only swaps	**-**	117.7
Fair value of derivative instruments - short term	**$ 11.7**	$ 294.5
Fixed-price swaps	**$ -**	$ 0.6
Costless collars	**-**	-
Basis-only swaps	**-**	-
Fair value of derivative instruments - long-term	**$ -**	$ 0.6

QEP Energy Production Volumes

The following table sets forth QEP Energy's volumes and average prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swap price per unit
			(in millions)	
Natural gas sales (MMbtu)				
2012	Swap	IFNPCR	62.2	$5.50
2012	Swap	IFPEPL	7.3	4.70
2012	Swap	NYMEX	69.5	4.93
2013	Swap	IFNPCR	65.7	5.66
2013	Swap	NYMEX	3.7	4.65
Oil sales (Bbls)				
2012	Swap	NYMEX WTI	1.8	$97.03
2013	Swap	NYMEX WTI	0.2	105.80
Ethane sales (Gals)				
2012	Swap	Mt. Belvieu Ethane	15.4	$0.64
Propane sales (Gals)				
2012	Swap	Mt. Belvieu Propane	7.7	$1.28

QEP Field Services NGL Volumes

QEP Field Services enters into commodity derivative transactions to manage price risk on extracted NGL volumes. The following table sets forth QEP Field Services' volumes and swap prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swap price per gallon
			(in millions)	
Ethane sales (Gals)				
2012	Swap	Mt. Belvieu Ethane	15.4	$0.64
Propane sales (Gals)				
2012	Swap	Mt. Belvieu Propane	15.4	$1.36

QEP Marketing Transactions

QEP Marketing enters into commodity derivative transactions to lock in a margin on natural gas volumes placed into storage. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of December 31, 2011:

Year	Type of Contract	Index	Total	Average Swaps hedged price per MMBtu
			(in millions)	
Natural gas sales (MMbtu)				
2012	Swaps	IFNPCR	3.3	$4.41
2013	Swaps	IFNPCR	0.9	4.77
Natural gas purchases (MMbtu)				
2012	Swaps	IFNPCR	0.3	$3.54

Note 7 – Debt

As of the indicated dates, the principal amount of QEP's debt, including amounts outstanding under its revolving credit facility, consisted of the following:

	December 31,	
	2011	2010
	(in millions)	
Revolving Credit Facility	**$ 606.5**	$ 400.0
7.5% Senior Notes due 2011	**-**	58.5
6.05% Senior Notes due 2016	**176.8**	176.8
6.80% Senior Notes due 2018	**138.6**	138.6
6.80% Senior Notes due 2020	**138.0**	138.0
6.875% Senior Notes due 2021	**625.0**	625.0
Total principal amount of debt	**1,684.9**	1,536.9
Less unamortized discount	**(5.5)**	(6.1)
Total long-term debt outstanding	**$ 1,679.4**	$ 1,530.8

Of the total debt outstanding on December 31, 2011, the $606.5 million drawn under the revolving credit facility (described below) due August 25, 2016, and the 6.05% Senior Notes due September 1, 2016, will mature within the next five years.

Credit Arrangements

During the third quarter of 2011, QEP entered into a new revolving credit facility, which matures in August 2016 and replaced the previous $1.0 billion credit facility. The terms of the new credit facility provide for loan commitments of $1.5 billion from a syndicate of financial institutions. The new credit facility provides for borrowing at short-term interest rates and contains customary covenants and restrictions. The agreement also contains provisions that would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for up to two additional one-year periods. Proceeds from borrowings under the credit facility were used to refinance outstanding amounts under the Company's previous credit facility and will be used for general corporate purposes, including working capital and capital expenditures. In conjunction with the replacement of the previous credit facility, QEP expensed $0.7 million of unamortized financing fees, which are included as a loss on extinguishment of debt on the Consolidated Income Statement. During the year ended December 31, 2011, QEP's weighted-average interest rate on borrowings from its credit facilities was 3.05%. At December 31, 2011 and 2010, QEP was in compliance with all of its debt covenants. At December 31, 2011, QEP had $606.5 million drawn and $4.1 million in letters of credit outstanding under the credit facility.

In conjunction with the Spin-off, QEP entered into a $500.0 million, 364-day term loan agreement with substantially the same initial pricing and terms as its then-existing $1.0 billion revolving credit agreement. Commitments under the term loan were terminated in August 2010 in conjunction with the issuance of $625.0 million of senior notes.

Senior Notes

The Company has $1,078.4 million principal amount of senior notes outstanding with maturities ranging from September 2016 to March 2021 and coupons ranging from 6.05% to 6.875%. The senior notes pay interest semi-annually, are unsecured, senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indenture governing QEP's senior notes contains customary events of default and covenants that may limit our ability to, among other things, place liens on its property or assets.

In August 2010, the Company purchased $638.0 million principal amount of its senior notes and paid required premium and accrued interest pursuant to the requirement in the notes' indenture relating to a change of control. The Company used cash on hand and proceeds from its revolving credit facility and term loan to purchase all of the tendered notes. Subsequent to the purchase of the tendered notes, the Company issued $625.0 million principal amount of senior notes due 2021 to refinance a portion of the indebtedness incurred to purchase the tendered senior notes. Proceeds from the senior notes offering were used to repay all of the borrowings outstanding under the term loan and a portion of outstanding borrowings under the Company's revolving credit.

Note 8 – Income Taxes

Details of income tax expenses and deferred income taxes from continuing operations are provided in the following tables. The components of income tax expenses were as follows:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Federal			
Current	**$ (5.3)**	$ (16.6)	$ 11.5
Deferred	**153.0**	172.9	101.3
State			
Current	**2.9**	(4.7)	2.6
Deferred	**3.8**	15.4	2.2
Total income tax expense	**$ 154.4**	**$ 167.0**	**$ 117.6**

The difference between the statutory federal income tax rate and the Company's effective income tax rate is explained as follows:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Federal income taxes statutory rate	**35.0%**	35.0%	35.0%
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**1.0%**	1.5%	0.9%
Non-deductible Spin-off costs	**0.0%**	0.5%	0.0%
Other	**0.3%**	-0.1%	-0.6%
Effective income tax rate	**36.3%**	**36.9%**	**35.3%**

Significant components of the Company's deferred income taxes were as follows:

	December 31,	
	2011	2010
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ 1,714.6**	$ 1,458.9
Energy-price derivatives	**45.9**	44.8
Total deferred tax liabilities	**1,760.5**	1,503.7
Deferred tax assets		
NOL and tax credit carryforwards	**232.9**	93.7
Employee benefits and compensation costs	**42.9**	32.3
Total deferred tax assets	**275.8**	126.0
Deferred income taxes - noncurrent	**$ 1,484.7**	$ 1,377.7
Deferred income taxes - current		
Energy-price derivatives	**(101.3)**	(43.9)
Other	**15.9**	16.1
Deferred income taxes - current asset (liability)	**$ (85.4)**	$ (27.8)

Federal and state NOLs and credits increased in 2011 primarily due to bonus depreciation, intangible drilling cost deductions, and QEP no longer being able to offset net operating losses against the taxable income of the formerly affiliated Questar Company and no longer having carryback years with positive taxable income. The amounts and expiration dates of operating loss and tax credit carryforwards at December 31, 2011:

	Expiration Dates	Amounts
	(in millions)	
U.S federal net operating loss carryforwards	2030-2031	$ 187.9
State net operating loss and credit carryforwards	2014-2031	29.3
U.S. alternative minimum tax credit	Indefinite	15.7
Total		$ 232.9

Note 9 – Commitments and Contingencies

QEP is involved in various commercial and regulatory claims and litigation and other legal proceedings that arise in the ordinary course of its business. Management does not believe any of them will have a material adverse effect on the Company's financial position, results of operations or cash flows. A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. Disclosures are provided for contingencies reasonably likely to occur which would have a material adverse effect on the Company's financial position, results of operations or cash flows. Some of the claims involve highly complex issues relating to liability, damages and other matters subject to substantial uncertainties and, therefore, the probability of liability or an estimate of loss cannot be reasonably determined.

Environmental Claims

United States of America v. QEP Field Services, Civil No. 208CV167, U.S. District Court for Utah. The U.S. Environmental Protection Agency (EPA) alleges that QEP Field Services (f/k/a QGM) violated the Clean Air Act (CAA) and seeks substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. Individual members of the Ute Indian Tribe's Business Committee intervened as co-plantiffs asserting the same CAA claims as the federal government. EPA contends that the potential to emit, on a hypothetically uncontrolled basis, for these facilities renders them "major sources" of emissions for criteria and hazardous air pollutants even though controls were installed and operated by QEP Field Services. Categorization of the facilities as "major sources" affects the particular regulatory program and requirements applicable to those facilities. EPA claims that QEP Field Services failed to obtain the necessary major source pre-construction or modification permits, and failed to comply with hazardous air-pollutant regulations for monitoring, testing and reporting, among other requirements. QEP Field Services contends that its facilities have pollution controls installed as part of their operational design that reduce their actual air emissions below major source thresholds, rendering them subject to different regulatory requirements applicable to non-major sources. QEP Field Services has vigorously defended against EPA's claims, and believes that the major source permitting and regulatory requirements at issue can be legally avoided by applying EPA's prior permitting practice for similar facilities elsewhere in Indian Country, among other defenses. Because of the complexities and uncertainties of this legal dispute, it is difficult to predict all reasonably possible outcomes; however, management believes the Company has accrued a reasonable loss contingency that is an immaterial amount, for the anticipated most likely outcome.

QEP Energy v. U.S. Environmental Protection Agency, No. 09-9538, U.S. Court of Appeals for the 10th Circuit. On July 10, 2009 QEP Energy filed a petition with the U.S. Court of Appeals challenging an administrative compliance order dated May 12, 2009 (Order), issued by EPA which asserts that QEP Energy's Flat Rock 14P well in the Uinta Basin and associated equipment is a major source of hazardous air pollutants and its operation fails to comply with certain regulations of the CAA. The Order required immediate compliance. QEP Energy denied that the drilling and operation of the 14P well and associated equipment violated any provisions of the CAA. QEP and EPA entered into an administrative order on consent, effective June 17, 2011, resolving all disputes associated with prospective CAA compliance at the Flat Rock 14P well. Among other matters, the order requires installation of pollution control equipment to destroy vapors from the well's dehydration equipment and ongoing monitoring and reporting associated with operation of that control equipment.

Commitments

Subsidiaries of QEP have contracted for firm-transportation services with various third-party pipelines through 2040. Market conditions, drilling activity and competition may prevent full utilization of the contractual capacity. In addition, QEP has contracts with third parties who provide drilling services, some of which extend through 2015. Annual payments and the corresponding years for both transportation contracts and drilling contracts are as follows:

	(in millions)
2012	**$ 116.2**
2013	**81.5**
2014	**79.4**
2015	**45.3**
2016	**41.8**
After 2016	**188.8**

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense amounted to $5.0 million, $4.5 million in 2010, and $4.0 million in 2009. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows:

	(in millions)
2012	**$ 5.6**
2013	**6.1**
2014	**5.6**
2015	**5.7**
2016	**5.8**
After 2016	**30.3**

Note 10 – Share-Based Compensation

QEP issues stock options and restricted shares under its Long-Term Stock Incentive Plan (LTSIP) and performance based share units under its Long-Term Cash Incentive Plan (LTCIP) to certain officers, employees and non-employee directors. Prior to the Spin-off, Questar granted share-based compensation to certain QEP employees using Questar common stock price as the basis. Stock options or restricted stock awards outstanding as of the Distribution Date were adjusted in order to generally preserve the benefits or potential benefits intended under the LTSIP. All such stock options were divided into two separate options, one relating to Questar common stock and one relating to QEP common stock. Each holder of Questar restricted stock was issued additional restricted shares of QEP common stock on a pro rata basis. The exercise price of options and the grant-day prices of restricted shares were modified using the ratio of the June 30, 2010, closing prices of Questar and QEP which were $14.66 or 32.23% and $30.83 or 67.77%, respectively.

QEP recognizes expense over time as stock options or restricted shares vest. Share-based compensation expense amounted to $22.0 million in 2011 compared to $16.1 million in 2010 and $13.4 million in 2009. The tax benefit recognized from share-based compensation expense was $1.5 million and $2.0 million during the years ended December 31, 2011 and 2010. During the year ended December 31, 2009, tax expense of $0.3 million was recognized from the related share-based compensation expense. Deferred share-based compensation is included in additional paid-in capital in the Consolidated Balance Sheets. There were 14.1 million shares available for future grants at December 31, 2011.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model in estimating the fair value of stock options for accounting purposes. Fair-value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model for measures the value of options traded on an exchange. The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	2011	2010	2009
	Stock Option Variables	Stock Option Variables	Range of Stock Option Variables
Fair value of options at grant date	**$18.80**	**$27.55**	**$31.06 - $35.38**
Risk-free interest rate	**2.1%**	**2.3%**	**1.78% - 2.51%**
Expected price volatility	**54.7%**	**30.3%**	**28.1% - 29.9%**
Expected dividend yield	**0.21%**	**1.18%**	**1.39% - 1.61%**
Expected life in years	**5.0**	**5.2**	**5.0 - 5.0**

Stock option transactions under the terms of the LTSIP for the year ended December 31, 2011, are summarized below:

	Options Outstanding	Weighted-Average Price	Aggregate Intrinsic Value
			(in millions)
Balance at December 31, 2010	1,914,922	19.02	
Granted	**202,235**	**39.07**	
Exercised	**(111,797)**	**15.69**	
Forfeited	**(1,666)**	**23.98**	
Balance at December 31, 2011	**2,003,694**	**$ 21.23**	**$ 18.1**

The total intrinsic value of options exercised was $2.7 million during the year ended December 31, 2011.

	Options Outstanding			Options Exercisable			Unvested Options	
Range of Exercise Prices	Number Outstanding at December 31, 2011	Weighted-Average Remaining Term in Years	Weighted-Average Exercise Price	Number Exercisable at December 31, 2011	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Number Unvested at December 31, 2011	Weighted-Average Exercise Price
						(in millions)		
$7.78 - $11.89	582,050	0.6	$ 8.57	582,050	$ 8.57		-	$ -
19.37 - 27.84	1,219,409	3.7	24.31	827,557	23.99		391,852	25.00
39.07	202,235	6.2	39.07	-	-		202,235	39.07
	2,003,694	**3.1**	**$ 21.23**	**1,409,607**	**$ 17.62**	**$ 16.5**	**594,087**	**$ 29.79**

Restricted Shares

Restricted share grants typically vest in equal installments over a three or four year period from the grant date. Several grants vest in a single installment after a specific period. The weighted-average vesting period of unvested restricted shares at December 31, 2011 was 12 months. Transactions involving restricted shares under the terms of the LTSIP are summarized below:

	Restricted Shares Outstanding	Weighted-Average Price
Unvested balance at December 31, 2010	966,961	29.05
Granted	**465,653**	**38.50**
Vested	**(307,140)**	**28.82**
Forfeited	**(25,722)**	**35.71**
Unvested balance at December 31, 2011	**1,099,752**	**$32.78**

At the time of the Spin-off, all outstanding options and restricted stock were bifurcated. QEP assumed responsibility for expensing approximately 819,000 unvested Questar stock options with a weighted-average price of $11.43 per share and approximately 614,000 unvested Questar restricted shares with a weighted-average price of $13.73 per share. QEP will recognize expense in future periods for these unvested share-based awards.

Performance Share Units

During the year ended December 31, 2011, the Company granted its first performance based share units. Vesting is dependent upon the Company's total shareholder return compared to a group of its peers. The awards are denominated in share units but delivered in cash at the end of the performance period. The weighted-average vesting period of unvested performance shares at December 31, 2011, was 26 months. Transactions involving performance shares units under the terms of the LTCIP are summarized below:

	Performance Shares Outstanding	Weighted-Average Price
Unvest balance at January 1, 2011	-	$ -
Granted	116,074	39.07
Distributed	-	-
Forfeited	(800)	39.07
Unvested balance at December 31, 2011	**115,274**	**$ 39.07**

Note 11 – Employee Benefits

Defined Benefit Pension Plans and Other Postretirement Benefits

In association with the Spin-off, the Company established defined-benefit pension and postretirement medical plans providing coverage to approximately 190 of its employees. QEP only retained liability for active employees, while all of the retired employees remained participants in Questar's retirement plans. At the Spin-off, Questar transferred certain assets and liabilities from its defined-benefit pension and postretirement medical plans related to QEP employees into QEP's newly established plans. The transfer resulted in the establishment of liabilities of $54.9 million related to the unfunded portions of the defined-benefit pension plans and other postretirement benefits with corresponding amounts in AOCI.

Pension-plan benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly pay period during the 10 years preceding retirement. QEP pension plans include a qualified and a nonqualified retirement plan. Postretirement health care benefits and life insurance are provided only to employees hired before January 1, 1997. The Company pays a portion of the costs of health-care benefits determined by an employee's years of service. The Company has capped its exposure to increasing medical care and life insurance costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company contribution is prorated based on an employee's years of service at retirement; only those employees with 25 or more years of service receive the maximum Company contribution. At December 31, 2011 and 2010, QEP's accumulated benefit obligation exceeded the fair value of plan assets as the plan is unfunded.

In 2011, the Company made contributions of $14.8 million to its funded pension plan. Although reported benefit obligations exceeded the fair value of pension and other postretirement plan assets at December 31, 2011, the Company monitors the funded status of its funded pension and other postretirement benefit plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to the Company's funded plan increase plan assets while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute approximately $6.3 million to its funded pension plan and approximately $1.3 million to its unfunded pension plan in 2012. The accumulated benefit obligation for all defined-benefit pension plans was $78.3 million and $57.4 million at December 31, 2011 and 2010.

The following table sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2011 and 2010, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2011 and 2010:

	Pension benefits		Other postretirement benefits	
	2011	2010	**2011**	2010
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 78.0**	$ -	**$ 4.5**	$ -
Service cost	**2.9**	1.3	**0.1**	0.1
Interest cost	**4.5**	2.1	**0.3**	0.1
Change in plan assumptions	**19.6**	(1.1)	**-**	(0.1)
Transfer due to Spin-off	**-**	75.7	**-**	4.4
Benefit payments	**(0.2)**	-	**-**	-
Actuarial loss (gain)	**(0.7)**	-	**1.0**	-
Benefit obligation at December 31,	**$ 104.1**	$ 78.0	**$ 5.9**	$ 4.5
Change in plan assets				
Fair value of plan assets at January 1,	**$ 30.9**	$ -	**$ -**	$ -
Actual gain (loss) on plan assets	**(1.3)**	4.1	**-**	-
Company contributions to the plan	**14.8**	1.6	**-**	-
Benefit payments	**(0.2)**	-	**-**	-
Transfer due to Spin-off	**-**	25.2	**-**	-
Fair value of plan assets at December 31,	**44.2**	30.9	**-**	-
Underfunded status (current and long-term)	**$ (59.9)**	$ (47.1)	**$ (5.9)**	$ (4.5)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (1.3)**	$ -	**$ -**	$ -
Other long-term liabilities	**(58.6)**	(47.1)	**(5.9)**	(4.5)
Total amount recognized in balance sheet	**$ (59.9)**	$ (47.1)	**$ (5.9)**	$ (4.5)
Amounts recognized in accumulated other comprehensive income (AOCI)				
Net actuarial loss (gain)	**$ 18.6**	$ (4.2)	**$ 1.0**	$ (0.1)
Prior service cost	**42.6**	47.8	**3.8**	4.2
Total amount recognized in AOCI	**$ 61.2**	$ 43.6	**$ 4.8**	$ 4.1

The following table sets forth the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the respective years ended December 31:

	Pension benefits			Other postretirement benefits		
	2011	2010	2009	**2011**	2010	2009
	(in millions)					
Components of net periodic benefit cost						
Service cost	**$ 2.9**	$ 1.3	$ -	**$ 0.1**	$ 0.1	$ -
Interest cost	**4.5**	2.1	-	**0.3**	0.1	-
Expected return on plan assets	**(2.6)**	(1.1)	-	**-**	-	-
Amortization of prior service costs	**5.3**	2.6	-	**0.3**	0.2	-
Net periodic benefit cost	**$ 10.1**	$ 4.9	$ -	**$ 0.7**	$ 0.4	$ -
Components recognized in other comprehensive income						
Net loss (gain)	**$ 22.9**	$ (4.2)	$ -	**$ 1.0**	$ -	$ -
Prior service cost	**-**	50.4	-	**-**	4.3	-
Recognized prior service cost	**(5.3)**	(2.6)	-	**(0.3)**	(0.1)	-
Total amount recognized in other comprehensive income	**$ 17.6**	$ 43.6	$ -	**$ 0.7**	$ 4.2	$ -

The estimated portion of net actuarial loss and net prior service cost for the pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 is $6.0 million, of which $5.3 million represents amortization of prior service cost recognition and the remaining $0.7 million represents amortization of net actuarial losses. The estimated portion to be recognized in net periodic cost for other postretirement benefits from accumulated other comprehensive income in 2012 is $0.4 million due to amortization of prior service cost recognition.

Following are the weighted-average assumptions (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate pension and other postretirement benefit obligations at December 31, 2011 and 2010:

	Pension benefits		Other postretirement benefits	
	2011	2010	**2010**	2009
Discount rate	**4.54%**	5.80%	**4.70%**	5.80%
Rate of increase in compensation	**3.60%**	3.60%	**n/a**	n/a

The discount rate assumptions used by the Company represents an estimate of the interest rate at which the pension and other postretirement obligations could effectively be settled on the measurement date.

Following are the assumptions used by the Company in determining the net periodic pension and other postretirement benefit cost for the years ended December 31:

	Pension benefits			Other postretirement benefits		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**5.80%**	5.70%	n/a	**5.80%**	5.70%	n/a
Expected long-term return on plan assets	**7.50%**	7.50%	n/a	**n/a**	n/a	n/a
Rate of increase in compensation	**3.60%**	3.60%	n/a	**n/a**	n/a	n/a

In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of return expected on the funds to be invested to provide benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. No plan assets are expected to be returned to the Company in 2012. In measuring the other postretirement benefit obligation the following assumed health care cost trend rates were used:

	December 31,	
	2011	2010
Health care cost trend rate assumed for next year	**8.00%**	8.00%
Ultimate health care cost trend rate	**5.00%**	5.00%
Year rate reaches ultimate trend rate	**2014**	2013

Service costs and interest costs may be sensitive to changes in the health-care inflation rate. A 1% increase in the health-care inflation rate would increase the yearly service and interest costs and the accumulated postretirement benefit obligation by negligible amounts. A 1% decrease in the health-care inflation rate would decrease the yearly service cost and interest cost and the accumulated postretirement-benefit obligation by negligible amounts.

Plan Assets

The Company's Employee Benefits Committee (EBC) has oversight over investment of retirement-plan assets. The EBC uses a third-party asset manager to assist in setting targeted-policy ranges for the allocation of assets among various investment categories. The EBC allocates pension-plan assets among broad asset categories and reviews the asset allocation at least annually. Asset-allocation decisions consider risk and return, future-benefit requirements, participant growth and other expected cash flows. These characteristics affect the level, risk and expected growth of postretirement-benefit assets. The EBC uses asset-mix guidelines that include targets for each asset category, return objectives for each asset group and the desired level of diversification and liquidity. These guidelines may change from time to time based on the committee's ongoing evaluation of each plan's risk tolerance. The EBC estimates an expected overall long-term rate of return on assets by weighting expected returns of each asset class by its targeted asset allocation percentage. Expected return estimates are developed from analysis of past performance and forecasts of long-term return expectations by third-parties. Responsibility for individual security selection rests with each investment manager, who is subject to guidelines specified by the EBC. The EBC sets performance objectives for each investment manager that are expected to be met over a three-year period or a complete market cycle, whichever is shorter. Performance and risk levels are regularly monitored to confirm policy compliance and that results are within expectations. Performance for each investment is measured relative to the appropriate index benchmark for its category. QEP securities may be considered for purchase at an investment manager's discretion, but within limitations prescribed by ERISA and other laws. There was no direct investment in QEP shares for the periods disclosed. The majority of retirement-benefit assets were invested as follows:

Equity securities: Domestic equity assets were mostly invested in a stock index fund, and a smaller portion was invested in an actively managed product, with a diversification goal representative of the whole U.S. stock market. Foreign equity securities consisted of developed market foreign equity assets which were invested in a fund that holds a diversified portfolio of common stocks of corporations in developed foreign countries and emerging market foreign equity assets that were invested in a fund that holds a diversified portfolio of common stocks of corporations in emerging foreign countries.

Debt securities: Investment grade intermediate-term debt assets are invested in funds holding a diversified portfolio of debt of governments, corporations and mortgage borrowers with average maturities of 5 to 10 years and investment grade credit ratings. Investment grade long-term debt assets are invested in a diversified portfolio of debt of corporate and non-corporate issuers, with an average maturity of more than ten years and investment grade credit ratings.

Although the actual allocation to cash and short-term investments is minimal (less than 1%), larger cash allocations may be held from time to time if deemed necessary for operational aspects of the retirement plan. Cash is invested in a high-quality, short-term temporary investment fund that purchases investment-grade quality short-term debt issued by governments and corporations.

Commingled funds: The EBC made the decision to invest all of the retirement plan assets in commingled funds as these funds typically have lower expense ratios and are more tax efficient than mutual funds. While commingled funds are classified as Level 3 assets because there are calculations involved in determining the net asset value of the funds, the underlying assets can be traced back to observable asset values and these commingled funds are audited annually by an independent accounting firm.

The fair value measurement provision of ASC 820 "Fair Value Measurements and Disclosures" defines fair value in applying generally accepted accounting principles as well as establishes a framework for measuring fair value and for making disclosures about fair-value measurements. Fair value measurement establishes a fair-value hierarchy. Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for an asset, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset. These Company's Level 3 investments are public investment vehicles valued using the net asset value (NAV) of the fund, but are considered Level 3 because they are commingled funds. The NAV is based on the value of the underlying assets owned by the fund excluding transaction costs, and minus liabilities. The following table sets forth by level, within the fair value hierarchy, the fair value of pension and postretirement benefit assets.

	As of December 31, 2011				Percentage of total
	Level 1	Level 2	Level 3	Total	
	(in millions except percentages)				
Cash and short-term investments	$ -	$ -	$ -	$ -	-
Total domestic equity securities	-	-	17.6	17.6	40%
Foreign equity securities					
Developed market foreign equity securities	-	-	10.8	10.8	24%
Emerging market foreign equity securities	-	-	2.2	2.2	5%
Debt securities					
Investment grade intermediate term debt	-	-	6.9	6.9	16%
Investment grade long-term debt	-	-	6.7	6.7	15%
Total investments	$ -	$ -	$ 44.2	$ 44.2	100%

	As of December 31, 2010				Percentage of total
	Level 1	Level 2	Level 3	Total	
	(in millions except percentages)				
Cash and short-term investments	$ -	$ -	$ -	$ -	-
Total domestic equity securities	-	-	12.4	12.4	40%
Foreign equity securities					
Developed market foreign equity securities	-	-	7.8	7.8	25%
Emerging market foreign equity securities	-	-	1.6	1.6	5%
Debt securities					
Investment grade intermediate term debt	-	-	4.6	4.6	15%
Investment grade long-term debt	-	-	4.5	4.5	15%
Total investments	$ -	$ -	$ 30.9	$ 30.9	100%

The following table presents a summary of changes in the fair value of QEP's Level 3 investments:

	Year ended December 31,	
	2011	**2010**
	(in millions)	
Balance at January 1,	**$ 30.9**	$ -
Transfer due to Spin-off	**-**	25.2
Employer contributions	**14.8**	1.6
Unrealized gains and losses	**(1.3)**	4.1
Benefits paid	**(0.2)**	
Balance at December 31,	**$ 44.2**	$ 30.9

Expected Benefit Payments
As of December 31, 2011, the following future benefit payments are expected to be paid:

	Pension	Postretirement benefits
	(in millions)	
2012	$ 1.9	$ 0.1
2013	2.0	0.1
2014	2.9	0.2
2015	3.2	0.2
2016	4.1	0.3
2017 through 2021	38.1	1.8

Employee Investment Plan

QEP employees may participate in the QEP Employee Investment Plan (EIP), a defined-contribution plan. The EIP allows eligible employees to purchase shares of QEP common stock or other investments through payroll deduction at the current fair market value on the transaction date. The Company currently contributes an overall match of 100% of employees' contribution up to a maximum of 6% of their qualifying earnings. In addition, from time-to-time at the discretion of management, the Company may contribute a discretionary portion beyond the company match. The Company recognizes expense equal to its yearly contributions, which amounted to $6.2 million and $4.2 million during the years ended December 31, 2011 and 2010.

Note 12 – Operations by Line of Business

QEP's lines of business include gas and oil exploration and production (QEP Energy), midstream field services (QEP Field Services) and marketing (QEP Marketing and other). Line of business information is presented according to senior management's basis for evaluating performance including differences in the nature of products, services and regulation. Following is a summary of operations by line of business for the three years ended December 31, 2011:

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2011						
Revenues						
From unaffiliated customers	$ 3,159.2	$ -	$ 2,213.2	$ 369.3	$ 576.7	$ -
From affiliated customers	-	(676.4)	-	96.2	580.2	-
Total Revenues	3,159.2	(676.4)	2,213.2	465.5	1,156.9	-
Operating expenses						
Purchased gas and oil expense	1,077.1	(573.8)	506.4	-	1,144.5	-
Lease operating expense	145.2	(3.0)	148.2	-	-	-
Gathering, processing and other	107.3	-	-	106.0	1.3	-
Natural gas, oil and NGL transportation and other handling costs	102.2	(93.1)	186.0	9.3	-	-
General and administrative	123.2	(6.5)	98.4	29.2	2.1	-
Production and property taxes	105.4	-	99.1	6.1	0.2	-
Depreciation, depletion and amortization	765.4	-	707.2	55.7	2.5	-
Other operating expenses	228.9	-	228.9	-	-	-
Total Operating expenses	2,654.7	(676.4)	1,974.2	206.3	1,150.6	-
Net gain (loss) from asset sales	1.4	-	1.4	-	-	-
Operating income	505.9	-	240.4	259.2	6.3	-
Interest and other income	4.1	(98.7)	4.0	0.1	98.7	-
Income from unconsolidated affiliates	5.5	-	0.1	5.4	-	-
Loss on early extinguishment of debt	(0.7)	-	-	-	-	(0.7)
Interest expense	(90.0)	98.7	(81.9)	(13.6)	(93.2)	-
Income taxes	(154.4)	-	(57.9)	(93.4)	(3.4)	0.3
Income from continuing operations	270.4	-	104.7	157.7	8.4	(0.4)
Income from continuing operations attributable to noncontrolling interest	(3.2)	-	-	(3.2)	-	-
Income from continuing operations attributable to QEP	$ 267.2	$ -	$ 104.7	$ 154.5	$ 8.4	$ (0.4)
Identifiable assets	$ 7,442.7	$ -	$ 5,815.7	$1,312.7	$ 314.3	$ -
Investment in unconsolidated affiliates	42.2	-	-	42.2	-	-
Cash capital expenditures	1,431.1	-	1,295.5	130.1	5.5	-
Accrued capital expenditures	1,445.9	-	1,338.8	101.6	5.5	-
Goodwill	$ 59.5	$ -	$ 59.5	$ -	$ -	$ -

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2010						
Revenues [1]						
From unaffiliated customers	$ 2,300.6	$ -	$ 1,456.3	$ 245.5	$ 598.8	$ -
From affiliated customers	-	(573.4)	-	73.7	499.7	-
Total Revenues	2,300.6	(573.4)	1,456.3	319.2	1,098.5	-
Operating expenses						
Purchased gas and oil expense	589.3	(493.5)	-	-	1,082.8	-
Lease operating expense	125.0	(2.3)	127.3	-	-	-
Gathering, processing and other	83.2	-	-	82.1	1.1	-
Natural gas, oil and NGL transportation	54.2	(71.3)	125.5	-	-	-
General and administrative	107.2	(6.3)	78.0	31.6	3.9	-
Seperation costs	13.5	-	-	-	-	13.5
Production and property taxes	82.5	-	77.8	4.4	0.3	-
Depreciation, depletion and amortization	643.4	-	592.5	48.9	2.0	-
Other operating expenses	69.1	-	69.1	-	-	-
Total Operating expenses	1,767.4	(573.4)	1,070.2	167.0	1,090.1	13.5
Net gain (loss) from asset sales	12.1	-	13.7	(1.6)	-	-
Operating income	545.3	-	399.8	150.6	8.4	(13.5)
Interest and other income	2.3	(87.1)	2.1	0.1	87.2	-
Income from unconsolidated affiliates	3.0	-	0.2	2.8	-	-
Loss on early extinguishment of debt	(13.3)	-	-	-	-	(13.3)
Interest expense	(84.4)	87.1	(78.5)	(7.6)	(85.4)	-
Income tax expense	(167.0)	-	(119.7)	(51.9)	(3.5)	8.1
Income from continuing operations	285.9	-	203.9	94.0	6.7	(18.7)
Income from continuing operations attributable to noncontrolling interest	(2.9)	-	-	(2.9)	-	-
Income from continuing operations attributable to QEP	$ 283.0	$ -	$ 203.9	$ 91.1	$ 6.7	$ (18.7)
Identifiable assets	6,785.3	-	5,391.9	1,197.5	195.9	
Investment in unconsolidated affiliates	44.5	-	-	44.5	-	
Cash capital expenditures	1,469.0	-	1,205.0	262.1	1.9	
Accrued capital expenditures	1,485.9	-	1,215.8	268.2	1.9	
Goodwill	59.6	-	59.6	-	-	

	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing & Other	QEP Resources
			(in millions)			
2009						
Revenues [1]						
From unaffiliated customers	$ 2,011.2	$ -	$ 1,356.0	$ 212.7	$ 442.5	$ -
From affiliated customers	-	(420.0)	-	51.9	368.1	-
Total Revenues	2,011.2	(420.0)	1,356.0	264.6	810.6	-
Operating expenses						
Purchased gas and oil expense	427.8	(362.8)	-	-	790.6	-
Lease operating expense	125.5	(2.0)	127.5	-	-	-
Gathering, processing and other	76.2	-	-	75.0	1.2	-
Natural gas, oil and NGL transportation	38.7	(50.0)	88.7	-	-	-
General and administrative	91.7	(5.2)	68.0	25.0	3.9	-
Seperation costs	-	-	-	-	-	-
Production and property taxes	62.9	-	58.3	4.6	-	-
Depreciation, depletion and amortization	559.1	-	512.8	44.3	2.0	-
Other operating expenses	45.3	-	45.3	-	-	-
Total Operating expenses	1,427.2	(420.0)	900.6	148.9	797.7	-
Net gain (loss) from asset sales	1.5	-	1.6	(0.1)	-	-
Operating income	585.5	-	457.0	115.6	12.9	-
Interest and other income	(185.1)	(70.7)	(185.7)	(0.2)	71.5	-
Income from unconsolidated affiliates	2.7	-	0.1	2.6	-	-
Loss on early extinguishment of debt	-	-	-	-	-	-
Interest expense	(70.1)	70.7	(63.9)	(6.0)	(70.9)	-
Income tax expense	(117.6)	-	(72.6)	(40.0)	(5.0)	-
Income from continuing operations	215.4	-	134.9	72.0	8.5	-
Income from continuing operations attributable to noncontrolling interest	(2.6)	-	-	(2.6)	-	-
Income from continuing operations attributable to QEP	$ 212.8	$ -	$ 134.9	$ 69.4	$ 8.5	$ -
Identifiable assets	5,828.9	-	4,633.0	929.2	266.7	
Investment in unconsolidated affiliates	43.9	-	-	43.9	-	
Cash capital expenditures	1,198.4	-	1,108.6	88.3	1.5	
Accrued capital expenditures	1,108.4	-	1,033.7	73.3	1.4	
Goodwill	60.1	-	60.1	-	-	

(1) Revenues for the years ended December 31, 2010 and 2009 were recast to reflect transportation and other handling costs as a separate line entitled "Natural gas, oil and NGL transportation and other handling costs" within operating expenses. See footnote 1, "Significant Accounting Policies" for additional information.

Note 13 – Quarterly Financial Information (Unaudited)

Following is a summary of unaudited quarterly financial information:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
			(in millions)		
2011					
Revenues (1)	**$ 617.9**	**$ 808.1**	**$ 879.9**	**$ 853.3**	**$ 3,159.2**
Operating income	**137.1**	**168.9**	**183.4**	**16.5**	**505.9**
Income from continuing operations	**73.8**	**93.5**	**102.4**	**0.7**	**270.4**
Net income (loss) attributable to QEP	**73.2**	**92.8**	**101.5**	**(0.3)**	**267.2**
Per share information attributable to QEP					
Basic EPS attributable to QEP	**$ 0.42**	**$ 0.52**	**$ 0.58**	**$ (0.01)**	**$ 1.51**
Diluted EPS attributable to QEP	**0.41**	**0.52**	**0.57**	**-**	**1.50**
2010					
Revenues (1)	$ 592.1	$ 542.3	$ 578.3	$ 587.9	$ 2,300.6
Operating income	142.9	127.6	149.3	125.5	545.3
Income from continuing operations	78.7	69.5	71.9	65.8	285.9
Discontinued operations, net of tax	21.2	22.0	-	-	43.2
Net income attributable to QEP	99.3	90.8	71.1	65.0	326.2
Per share information attributable to QEP					
Basic EPS from continuing operations	$ 0.45	$ 0.39	$ 0.40	$ 0.37	$ 1.61
Basic EPS attributable to QEP	0.57	0.52	0.40	0.37	1.86
Diluted EPS from continuing operations	0.44	0.39	0.40	0.37	1.60
Diluted EPS attributable to QEP	0.56	0.51	0.40	0.37	1.84

(1) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs which have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented. See Note 1, "Summary of Significant Accounting Policies" for additional information. The following table presents prior periods presentation of revenues as previously disclosed:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2011	$ 596.2	$ 784.1	$ 852.4	n/a	n/a
2010	580.2	529.6	564.6	572.0	2,246.4

Note 14 – Supplemental Gas and Oil Information (Unaudited)

The Company is making the following supplemental disclosures of gas and oil producing activities, in accordance with ASC 932 "Extractive Activities – Oil and Gas" as amended by ASU 2010-03 "Oil and Gas Reserve Estimation and Disclosures" and SEC Regulation S-X.

The Company uses the successful efforts accounting method for its gas and oil exploration and development activities. All properties are located in the United States.

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

	December 31,	
	2011	2010
	(in millions)	
Proved properties	$ 8,172.4	$ 6,874.3
Unproved properties	326.8	322.0
Proved properties	8,499.2	7,196.3
Accumulated depreciation, depletion and amortization	(3,339.2)	(2,454.4)
Net capitalized costs	$ 5,160.0	$ 4,741.9

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. Development costs incurred reflect accrued capital costs of $43.2 million and ARO expenses of $3.4 million in 2011. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $533.6 million in 2011, $434.2 million in 2010 and $216.1 million in 2009.

	Year Ended December 31,		
	2011	2010	2009
	(in millions)		
Property acquisitions			
Unproved	**$ 48.0**	$ 109.1	$ 215.1
Proved	**0.1**	0.2	6.4
Exploration (capitalized and expensed)	**36.5**	146.4	92.9
Development	**1,267.8**	988.8	741.1
Total costs incurred	**$ 1,352.4**	$ 1,244.5	$ 1,055.5

Results of Operations

Following are the results of operations of QEP Energy gas and oil exploration and development activities, before allocated corporate overhead and interest expenses.

	Year Ended December 31,		
	2011	2010	2009
	(in millions)		
Revenues	**$ 2,213.2**	$ 1,456.3	$ 1,356.0
Production costs	**433.3**	330.6	274.5
Exploration expenses	**10.5**	23.0	25.0
Depreciation, depletion and amortization	**707.2**	592.5	512.8
Abandonment and impairment	**218.4**	46.1	20.3
Total expenses	**1,369.4**	992.2	832.6
Income before income taxes	**843.8**	464.1	523.4
Income taxes	**(300.4)**	(171.8)	(183.2)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ 543.4**	$ 292.3	$ 340.2

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of proved gas and oil reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which includes the compliance oversight of a multi-functional reserves review committee responsible to the Company's board of directors. QEP Energy's estimated proved reserves have been prepared by Ryder Scott Company, L.P., independent reservoir engineering consultants, in accordance with the SEC's Regulation S-X and ASC 932 as amended. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation.

All of QEP Energy's proved undeveloped reserves at December 31, 2011, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 217 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural gas reserves in the PAPA is governed by the BLM's September 2008, ROD on the FSEIS. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas defined in the PAPA. The ROD contains additional requirements and restrictions on the sequence of development of the PAPA, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development of the PAPA that is beyond the control of the Company. The Company has an ongoing development plan for the PAPA and the financial capability to continue development in the manner estimated.

	Natural Gas (Bcf)	Oil (Mbbl)	NGL (Mbbl)	Natural Gas Equivalents (Bcfe)
Proved reserves				
Balance at January 1, 2009	2,028.5	26,079.7	5,505.9	2,218.1
Revisions of previous estimates	(318.9)	2,237.3	1,115.4	(298.8)
Extensions and discoveries	982.4	3,610.7	1,761.0	1,014.6
Purchase of reserves in place	1.7	124.0	0.9	2.5
Sale of reserves in place	-	-	-	-
Production	(168.7)	(2,746.7)	(705.0)	(189.5)
Balance at December 31, 2009	2,525.0	29,305.0	7,678.2	2,746.9
Revisions of previous estimates	46.3	640.0	4,779.8	78.6
Extensions and discoveries	248.4	26,085.6	6,137.3	441.8
Purchase of reserves in place	0.2	-	-	0.2
Sale of reserves in place	(3.2)	(774.1)	-	(7.8)
Production	(203.8)	(2,979.8)	(1,225.8)	(229.0)
Balance at December 31, 2010	2,612.9	52,276.7	17,369.5	3,030.7
Revisions of previous estimates (1)	**(270.1)**	**1,794.0**	**39,290.5**	**(23.5)**
Extensions and discoveries (2)	**641.9**	**17,360.4**	**22,600.7**	**881.6**
Purchase of reserves in place	**1.9**	**17.0**	**12.0**	**2.1**
Sale of reserves in place	**(0.8)**	**(192.0)**	**-**	**(1.9)**
Production	**(236.4)**	**(3,741.3)**	**(2,715.6)**	**(275.2)**
Balance at December 31, 2011	**2,749.4**	**67,514.8**	**76,557.1**	**3,613.8**
Proved developed reserves				
Balance at January 1, 2009	1,128.1	19,466.7	4,071.9	1,269.4
Balance at December 31, 2009	1,178.7	22,428.0	4,919.2	1,342.8
Balance at December 31, 2010	1,404.8	25,115.6	9,342.9	1,611.5
Balance at December 31, 2011	**1,538.3**	**32,955.5**	**38,388.1**	**1,966.3**
Proved undeveloped reserves				
Balance at January 1, 2009	900.4	6,613.0	1,434.0	948.7
Balance at December 31, 2009	1,346.3	6,877.0	2,759.0	1,404.1
Balance at December 31, 2010	1,208.1	27,161.1	8,026.6	1,419.2
Balance at December 31, 2011	**1,211.1**	**34,559.3**	**38,169.0**	**1,647.5**

(1) Revisions of previous estimates include 173.7 Bcfe negative impact due to performance revisions offset by 150.2 Bcfe positive impact from other revisions. The 173.7 Bcfe performance revisions were due to the reduction of natural gas volumes of 209.8 Bcf, offset by an increase in NGL volumes of 33.2 MMbbls, which is included in other revisions. The primary reason for the increase in the NGL volumes, or 31.8 MMbbls, relates to the completion of the Blacks Fork II plant and the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP Energy's Pinedale production, offset by a reduction in the dry natural gas reserve related to shrink of about 59.6 Bcf. The remaining performance related reduction in the natural gas reserves was primarily related to the removal of certain PUD locations in the Haynesville/Cotton Valley area to recognize the 80-acre increased density development plan.

(2) Extensions and discoveries increased proved reserves by 881.6 Bcfe, primarily related to extensions and discoveries at the Haynesville/Cotton Valley area (358.8 Bcfe), Unita Basin area (189.1 Bcfe) and Pinedale Anticline area (161.2 Bcfe). All of these extensions and discoveries related to new well completions and associated new PUD locations. Estimates of the quantity of proved reserves from the Company's Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling activity, producing well performance and the development and application of reliable technologies. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes. With the application of the amendments of ASC 932 in ASU 2010-03, reserves associated with Pinedale increased density drilling are included in extensions and discoveries for the years ended December 31, 2011, 2010 and 2009, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31, 2011, 2010 and 2009 by applying prices, which were the simple average of the first-of-the-month prices for the 12-months of 2011, 2010 and 2009 with consideration of known contractual price changes. The prices used do not include any impact of QEP's commodity derivatives portfolio. The average price per Mcf used to calculate proved natural gas reserves was $3.46 in 2011, $3.85 in 2010, and $3.06 in 2009. The aggregate average price per barrel used to calculate proved oil reserves was $82.96 in 2011, $65.91 in 2010, and $49.32 in 2009. The aggregate average price per barrel used to calculate proved NGL reserves was $41.55 in 2011, $39.13 in 2010, and $31.15 in 2009. Year-end operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop booked proved undeveloped reserves are approximately $614.9 million in 2012, $788.8 million in 2013 and $757.7 million in 2014.

The assumptions used to derive the standardized measure of future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating QEP or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will probably differ from those required to be used in these calculations.
- Future operating and capital costs will probably differ from those required to be used in these calculations.
- Future market conditions, government regulations and reservoir conditions may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The standardized measure of future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Future cash inflows	**$ 18,300.6**	$ 14,174.8	$ 9,419.3
Future production costs	**(4,276.1)**	(3,701.8)	(2,841.8)
Future development costs	**(3,250.0)**	(2,275.9)	(2,252.7)
Future income tax expenses	**(2,837.1)**	(1,957.6)	(674.0)
Future net cash flows	**7,937.4**	6,239.5	3,650.8
10% annual discount for estimated timing of net cash flows	**(4,411.8)**	(3,533.9)	(2,207.8)
Standardized measure of discounted future net cash flows	**$ 3,525.6**	$ 2,705.6	$ 1,443.0

The principal sources of change in the standardized measure of future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Balance at January 1,	**$ 2,705.6**	$ 1,443.0	$ 2,001.9
Sales of gas, oil and NGL produced during the period, net of production costs	**(1,779.9)**	(1,125.7)	(1,081.5)
Net change in sales prices and in production (lifting) costs related to future production	**1,472.5**	1,775.8	(813.1)
Net change due to extensions, discoveries and improved recovery	**1,806.4**	789.1	1,291.6
Net change due to revisions of quantity estimates	**(48.2)**	140.4	(380.4)
Net change due to purchases and sales of reserves in place	**(7.9)**	(25.8)	6.4
Previously estimated development costs incurred during the period	**533.6**	434.2	216.1
Changes in estimated future development costs	**(1,110.4)**	(325.4)	(347.4)
Accretion of discount	**355.4**	170.9	256.4
Net change in income taxes	**(411.4)**	(582.4)	295.8
Other	**9.9**	11.5	(2.8)
Net change	**820.0**	1,262.6	(558.9)
Balance at December 31,	**$ 3,525.6**	$ 2,705.6	$ 1,443.0

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

On November 11, 2011 the Audit Committee of the Board of Directors of QEP Resources, Inc. (the "Company") approved the engagement of PricewaterhouseCoopers LLP ("PWC") as the Company's independent registered public accounting firm for the year ending December 31, 2012. PWC informed the Company that it completed the prospective client evaluation process on November 15, 2011. In connection with the selection of PWC, also on November 11, 2011, the Audit Committee informed Ernst & Young LLP ("E&Y") that it will be dismissed as the Company's independent registered public accounting firm no later than the date of the filing of the Company's Form 10-K for the 2011 fiscal year. The decision to change auditors was the result of a request for proposal process that included the largest four public accounting firms.

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, neither the Company nor anyone on its behalf has consulted with PWC with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Registrant's consolidated financial statements, and neither written nor oral advice was provided to the Company that PWC concluded was an important factor considered by the Company in reaching a decision as to any accounting, auditing or financial reporting issue; (ii) any matter that was either the subject of disagreement (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) or a reportable event (as defined by Item 304(a)(1)(v) of Regulation S-K).

The report of E&Y on the Company's consolidated financial statements for the years ended December 31, 2010 and 2009 did not contain an adverse opinion or disclaimer of an opinion, and was not qualified or modified as to uncertainty, audit scope or accounting principles, except that the report includes an explanatory paragraph related to the Company's adoption of ASC 810-10-65-1, "Noncontrolling Interests in Consolidated Financial Statements", and SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting."

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, there were no disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) with E&Y on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of E&Y, would have caused E&Y to make reference to the subject matter of the disagreement in its report on the consolidated financial statements for such year.

During the years ended December 31, 2011, 2010 and 2009, and through February 24, 2012, there were no reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

The Company has provided E&Y with a copy of the above disclosures, and E&Y has furnished the Company with a letter addressed to the SEC stating it agrees with the statements made above. For a copy of E&Y's letter see Exhibit No. 16.1 filed to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2011.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of December 31, 2011. Based on such evaluation, such officers have concluded that, as of December 31, 2011, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specificed by the SEC's rules and forms and that information is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Controls

There were no changes in the Company's internal controls over financial reporting that occurred during the quarter ended December 31, 2011, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control Over Financial Reporting

QEP's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). QEP Resources, Inc.'s internal control over financial reporting is a process designed under the supervision of QEP's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2011, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2011, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2011, which is included in Item 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's annual Meeting of Stockholders to be held on May 15, 2012, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2011 (Proxy Statement), and is incorporated by reference herein.

Information about the Company's executive officers can be found in Item 1 of Part I in this Annual Report.

Information concerning compliance with Section 16(a) of the Exchange Act will set forth in the Proxy Statement and is incorporated herein by reference.

The Company has a Business Ethics and Compliance Policy (Ethics Policy) that applies to all of its directors, officers (including its Chief Executive Officer and Chief Financial Officer) and employees. QEP has posted the Ethics Policy on its website, www.qepres.com. Any waiver of the Ethics Policy for executive officers must be approved only by the Company's Board of Directors. QEP will post on its website any amendments to or waivers of the Ethics Policy that apply to executive officers.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in the Proxy Statement and is incorporated herein by reference.

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

The information required by Item 12 will be set forth in the Proxy Statement and is incorporated herein by reference.

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

The information required by Item 13 will be set forth in the Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 will be set forth in the Proxy Statement and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8. Financial Statements and Supplementary Data of this report.

(b) **Exhibits.** The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated as of May 18, 2010, between Questar Market Resources, Inc., a Utah corporation, and QEP Resources, Inc., a Delaware corporation. (Incorporated by reference to Exhibit No. 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
2.2	Separation and Distribution Agreement dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit No. 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
3.1	Certificate of Incorporation dated May 18, 2010. (Incorporated by reference to Exhibit No. 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
3.2	Amended and Restated Bylaws, deemed effective May 18, 2010. (Incorporated by reference to Exhibit No. 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
3.5	Certificate of Designations of Series A Junior Participating Preferred Stock of QEP Resources, Inc. (Incorporated by reference to Exhibit 2. of QEP Resources, Inc.'s Registration Statement on Form 8-A filed with the Securities and Exchange Commission on June 30, 2010.)

Exhibit No.	Description
4.1	Form of the Company's 6.05% Notes due 2016. (Incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 15, 2006.)
4.2	Form of Officers' Certificate setting forth the terms of the Company's 6.05% Notes due 2016. (Incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 15, 2006.)
4.3	Form of the Company's 6.80% Notes due 2018. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 1, 2008.)
4.4	Form of Officers' Certificate setting forth the terms of the Company's 6.80% Notes due 2018. (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 1, 2008.)
4.5	Form of the Company's 6.80% Notes due 2020. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 2, 2009.)
4.6	Form of Officers' Certificate setting forth the terms of the Company's 6.80% Notes due 2020. (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 2, 2009.)
4.7	Officers' Certificate, dated as of August 16, 2010 (including the form of the Company's 6.875% Notes due 2021). (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 16, 2010.)
4.8	Rights Agreement, dated as of June 30, 2010, between QEP Resources, Inc. and Wells Fargo Bank, N.A., which includes the Form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Stock as Exhibit C (Incorporated by reference to Exhibit 1 of QEP Resources, Inc.'s Registration Statement on Form 8-A filed with the Securities and Exchange Commission on June 30, 2010), as amended by the First Amendment to Rights Agreement, dated as of February 14, 2012 (Incorporated by reference to Exhibit 4.1 of QEP Resources, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 14, 2012.)
10.1	Credit Agreement, dated as of August 25, 2011, among QEP Resources, Inc., Wells Fargo Bank, National Association, as the administrative agent, letter of credit issuer and swing line lender, and the lenders party thereto. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 25, 2011.)
10.2	Senior Unsecured Bridge Loan Agreement, dated as of June 30, 2010, among QEP Resources, Inc, as borrower, Deutsche Bank AG Cayman Islands Branch, as administrative agent, Bank of America, N.A. and BMO Capital Markets Financing, Inc., as co-syndication agents, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents, and the lenders party thereto. (Incorporated by reference to Exhibit No. 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 1, 2010.)
10.3	Employee Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.4	Tax Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit No. 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.5	Transition Services Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit No. 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.6+	QEP Resources, Inc. Deferred Compensation Plan for Directors (Incorporated by reference to Exhibit No. 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.7+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Charles B. Stanley (Incorporated by reference to Exhibit No. 10.5 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.8+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Richard J. Doleshek (Incorporated by reference to Exhibit No. 10.6 to the Company's Current Report on

Exhibit No.	Description
	Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.9+	QEP Resources, Inc. 2010 Annual Management Incentive Plan II (Incorporated by reference to Exhibit No. 10.7 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.10+	QEP Resources, Inc. 2010 Long-Term Cash Incentive Plan (Incorporated by reference to Exhibit No. 10.8 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010).
10.11+	QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan (Incorporated by reference to Exhibit No. 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.12+	QEP Resources, Inc. Executive Severance Compensation Plan (Incorporated by reference to Exhibit No. 10.10 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010), as amended and restated by the QEP Resources, Inc. Executive Severance Compensation Plan (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 16, 2012.)
10.13+	QEP Resources, Inc. Deferred Compensation Wrap Plan (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on December 1, 2011.)
10.14+	QEP Resources, Inc. Supplemental Executive Retirement Plan (Incorporated by reference to Exhibit No. 10.12 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.15+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to certain key executives. (Incorporated by reference to Exhibit No. 10.1. to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.16+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.17+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to certain key executives. (Incorporated by reference to Exhibit No. 10.3. to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.18+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.19+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to certain key executives. (Incorporated by reference to Exhibit No. 10.5 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.20+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.6 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.21+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to non-employee directors. (Incorporated by reference to Exhibit No. 10.7 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.22+	QEP Resources, Inc. Form of Phantom Stock Agreement for phantom stock granted to non-employee directors. (Incorporated by reference to Exhibit No. 10.8 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.23+	QEP Resources, Inc. Form of Restricted Stock Units Agreement for restricted stock units granted to Mr. Keith O. Rattie. (Incorporated by reference to Exhibit No. 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
12.1*	Ratio of earnings to fixed charges.
16.1	QEP Resources, Inc. Change in Registrant's Certifying Accountant. (Incorporated by reference to Exhibit No. 4.01 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2011.)
21.1*	Subsidiaries of the Company.

Exhibit No.	Description
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers and Geologists.
23.3*	Qualifications and Report of Independent Petroleum Engineers and Geologists.
24*	Power of Attorney
31.1*	Certification signed by Charles B. Stanley, QEP Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification signed by Richard J. Doleshek, QEP Resources, Inc. Executive Vice President, Chief Financial Officer and Treasurer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc. President and Chief Executive Officer and Executive Vice President, Chief Financial Officer and Treasurer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith
\+ Indicates a management contract or compensatory plan or arrangement

(c) **Financial Statement Schedule:**

QEP RESOURCES, INC.
Schedule of Valuation and Qualifying Accounts

Description	Beginning Balance	Amounts charged (credited) to expense	Deductions for accounts written off and other	Ending Balance
		(in millions)		
Year ended December 31, 2011				
Allowance for bad debts	**$ 2.3**	**$ 0.2**	**$ (0.8)**	**$ 1.7**
Year ended December 31, 2010				
Allowance for bad debts	3.0	(0.3)	(0.4)	2.3
Year ended December 31, 2009				
Allowance for bad debts	2.7	0.4	(0.1)	3.0

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 24th day of February, 2012.

QEP RESOURCES, INC.
(Registrant)

By: /s/ C. B. Stanley
C. B. Stanley
President and Chief Executive Officer

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

/s/ C. B. Stanley C. B. Stanley	President and Chief Executive Officer Director (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ B. Kurtis Watts B. Kurtis Watts	Vice President and Controller (Principal Accounting Officer)
*Keith O. Rattie	Chairman of the Board; Director
*Phillips S. Baker, Jr.	Director
*L. Richard Flury	Director
*David Trice	Director
*Robert E. McKee III	Director
*M. W. Scoggins	Director
*C. B. Stanley	Director
February 24, 2012 Date	*By /s/ C. B. Stanley C. B. Stanley, Attorney in Fact

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Corporate Information

HISTORY

QEP Resources, Inc. is a leading independent natural gas and oil exploration and production company. Our company's origin dates back to a large natural gas discovery in southwestern Wyoming in 1922. We have operated under various names over the years, including Mountain Fuel Supply Company, Celsius Energy Company, Universal Resources Corporation, Questar Market Resources, Inc., Questar Exploration and Production Company, Questar Gas Management Company, and Questar Energy Trading Company. On June 30, 2010, shares of QEP Resources, Inc. began trading as a new publicly-traded, independent natural gas and oil exploration and production company after being spun-off from Questar Corporation in a pro-rata tax-free dividend. While QEP Resources is a major Rocky Mountain producer, over 50% of our net production comes from the Midcontinent area. We also gather, compress, treat and process natural gas in our core producing areas. Today, QEP Resources, Inc. is a holding company with three principal lines of business: gas and oil exploration, development and production; midstream field services; and energy marketing.

MISSION STATEMENT

QEP Resources is a leading independent oil and natural gas exploration and production company. We create value for our shareholders through superior execution, returns-focused growth, and a low cost structure. We operate in a safe and environmentally responsible manner. We support the communities in which we live and work. We invest in our employees and create an environment of innovation and creativity. We take pride in our record of responsible corporate citizenship dating back to 1922 and strive to continue that legacy.

HEALTH, SAFETY AND ENVIRONMENTAL STEWARDSHIP

We are committed to protecting the well-being of our employees and communities. We have lowered rates of injuries to employees and contractors, reduced spills and atmospheric emissions. To drive further improvement, we are implementing a new Health, Safety and Environmental Management System and imbedding our HSE organization into our operations teams to improve personnel and process safety, while minimizing the impact of our activities on the environment.

CODE OF CONDUCT

QEP Resources' Code of Conduct is intended to reflect and preserve the high standards of business conduct that are a company tradition. QEP is committed to full compliance with both the letter and the spirit of the numerous and sometimes complex laws and regulations that govern the company. This statement has been approved by the Audit Committee of QEP's board of directors and by executive management.

The following policies apply to the conduct of all employees, officers and directors of the QEP group of companies (referred to collectively as QEP):

- QEP is committed to dealing fairly with employees, customers, suppliers and competitors, and expects directors, officers, and employees to comply with this standard;
- QEP adheres to the highest standard of business ethics and seeks to maintain the respect of government and regulatory authorities, customers, the public, the business community and QEP shareholders; and
- QEP and its employees, officers, and directors are required to comply with applicable laws, rules and regulations and must avoid any unlawful practice.

The Code of Conduct is available on QEP's Web site, www.qepres.com.

CORPORATE INFORMATION

COMMON STOCK

- 177.2 million shares issued, par value $0.01 per share, at Dec. 31, 2011
- Listed on the New York Stock Exchange, ticker symbol: QEP

SHAREHOLDER RECORDS, TRANSFER AND PAYING AGENT

Wells Fargo Bank, N.A.
Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075-1139
Tel. 866-877-6324 (toll free)

FORM 10-K

QEP Resources' Form 10-K — an annual report of company operations filed with the Securities and Exchange Commission — is available online at www.sec.gov, or at www.qepres.com or by calling QEP Investor Relations at 303-672-6988.

ANNUAL MEETING

The 2012 Annual Meeting of Shareholders will be held at 8 a.m. MDT Wednesday, May 15, 2012, at the QEP offices located at 1050 17th Street, Suite 500, Denver, Colorado.

ANALYST AND MEDIA CONTACT

Scott Gutberlet
Director, Investor Relations
Tel. 303-672-6988
Email: scott.gutberlet@qepres.com

AUDITORS

Ernst & Young LLP
Independent Registered
Public Accounting Firm
370 17th Street, Suite 3300
Denver, CO 80202-5663

PRINCIPAL OFFICE

QEP Resources
1050 17th Street
Suite 500
Denver, CO 80265
Tel. 303-672-6900

MAJOR SUBSIDIARIES

QEP Energy Company
QEP Field Services Company
QEP Marketing Company

CORPORATE WEB SITE

Corporate information is available online at www.qepres.com

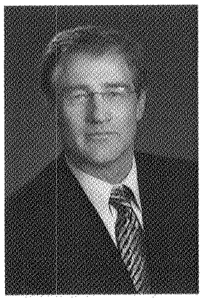
COMPANY CERTIFICATION

In 2011, the company submitted the annual certification of its chief executive officer regarding the company's compliance with the New York Stock Exchange's corporate governance listing standards pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

OFFICERS

Charles B. Stanley
President and CEO, QEP Resources
Richard J. Doleshek
Executive Vice President, CFO and Treasurer, QEP Resources
Jay B. Neese
Executive Vice President, QEP Resources
Eric L. Dady
Vice President and General Counsel, QEP Resources
Margo D. Fiala
Vice President, Human Resources, QEP Resources
Abigail L. Jones
Vice President, Compliance, Corporate Secretary and Assistant General Counsel, QEP Resources
J. Paul Matheny
Vice President and Chief of Staff, QEP Energy
Austin S. Murr
Vice President, Land and Business Development, QEP Energy
Michael D. Penner
Vice President, Midcontinent Division, QEP Energy
Vincent G. Rigatti
Vice President, Northern Region, QEP Energy
Jeffery R. Tommerup
Vice President, Southern Region, QEP Energy
Jim E. Torgerson
Senior Vice President, Operations, QEP Energy
Perry H. Richards
Senior Vice President, QEP Field Services
Kevin R. Peretti
Vice President, Engineering and Operations, QEP Field Services

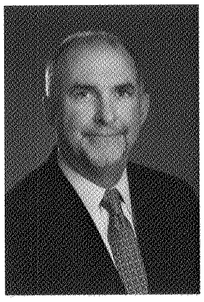
BOARD OF DIRECTORS



Mr. Phillips S. Baker, Jr., (52) President, chief executive officer and director, Hecla Mining Company; former chief financial officer and chief operating officer, Hecla; Questar director 2004-2010; QEP director since 2010.

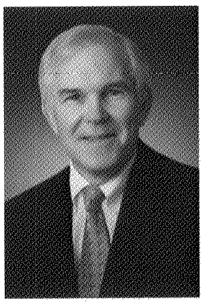
Dr. M. W. Scoggins, (64) President, Colorado School of Mines; retired executive vice president, ExxonMobil Production Co.; previously held senior executive positions with Mobil Corp.; director of Venoco, Inc., and Cobalt International Energy; Questar director 2005-2010; QEP director since 2010.

Mr. L. Richard Flury, (64) Retired chief executive, gas and power, BP plc; former chief executive worldwide exploration and production, Amoco Corp; non-executive chairman, Chicago Bridge and Iron NV and director, Callon Petroleum Co.; Questar director 2002-2010; QEP director since 2010.

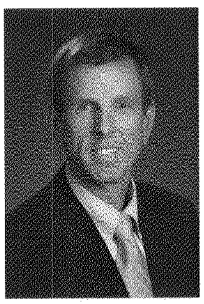


Mr. Charles B. Stanley, (53) President and chief executive officer, QEP; former executive vice president and chief operating officer, Questar; director Hecla Mining Company; Questar director 2002-2010; QEP director since 2010.

Mr. Robert E. McKee, III, (65) Retired executive vice president, exploration and production, Conoco Phillips and Conoco Corp.; director Parker Drilling Co. and Post Oak Bank; Questar director 2003-2010; QEP director since 2010.



Mr. David A. Trice, (63) Retired chairman and chief executive officer, Newfield Exploration Company; director of New Jersey Resources Corporation, Crazy Mountain Brewery, LLC. and McDermott International, Inc.; QEP director since 2011.



Mr. Keith O. Rattie, (58) Non-executive chairman and director of the Company since 2010; former president and chief executive officer, Questar Corporation; non-executive chairman of Questar Corporation; director of ENSCO International, Rockwater Energy Solutions, Inc. and Zions First National Bank.

QEP Resources, Inc.

www.qepres.com