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, 2006

QUESTAR MARKET RESOURCES, INC.

STATE OF UTAH	0-30321	87-0287750
(State or other jurisdiction of incorporation or organization)	(Commission File No.)	(I.R.S. Employer Identification No.)

180 East 100 South, P.O. Box 45601, Salt Lake City, Utah 84145-0601
(Address of principal executive offices)
(801) 324-2600
(Registrant's telephone number)

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

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

Common stock, $1.00 par value

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

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

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

Indicate by check mark 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [ ]   Accelerated filer [ ]   Non-accelerated filer [X]

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

Aggregate market value of the voting common equity held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second quarter (June 30, 2006): $0.

On February 28, 2007, 4,309,427 shares of the registrant's common stock, $1.00 par value, were outstanding (all shares are owned by Questar Corporation).

Registrant meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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Where You Can Find More Information

Questar Market Resources, Inc. (Market Resources or the Company), is a wholly owned subsidiary of Questar Corporation (Questar). Both Questar and Market Resources file annual, quarterly, and current reports with the Securities and Exchange Commission (SEC). The public may read and copy these reports and any other materials filed with the SEC at its Public Reference Room at 450 Fifth Street, N.W., 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 a web site that contains information filed electronically that can be accessed over the Internet at www.sec.gov.

Interested parties can also access financial and other information via Questar's web site at www.questar.com. Questar and Market Resources make available, free of charge, through the web site 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. Access to these reports is provided as soon as reasonably practical after such reports are electronically filed with the SEC. Questar's web site also contains Statements of Responsibility for Board Committees, Corporate Governance Guidelines and the 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 Market Resources, 180 East 100 South Street, P.O. Box 45601, Salt Lake City, Utah 84145-0601 (telephone number (801) 324-2600).

Forward-Looking Statements

This Annual Report may contain or incorporate 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. They 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. In particular, these include statements relating to future actions, prospective services or products, future performance or results of current and anticipated services or products, exploration efforts, expenses, the outcome of contingen cies such as legal proceedings, trends in operations and financial results.

Any or all forward-looking statements may turn out to be wrong. 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. Among factors that could cause actual results to differ materially are:

- the risk factors discussed in Part I, Item 1A of this Annual Report;
- general economic conditions, including the performance of financial markets and interest rates;
- changes in industry trends;
- changes in laws or regulations; and
- other factors, most of which are beyond control.

Market Resources undertakes no obligation to publicly correct or update the forward-looking statements in this Annual Report, in other documents, or on the web site 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.
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 Statement of Financial Accounting Standards (SFAS) 133, as amended, 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 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 feet of natural gas equivalents.
development well
A well drilled into a known producing formation in a previously discovered field.

dewpoint
A specific temperature and pressure at which hydrocarbons condense to form a liquid.
dry hole
A well drilled and found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed expenses and taxes.
dth
Decatherms or ten therms. One dth equals one million Btu or approximately one Mcf.
dthe
Decatherms of natural gas equivalents.
equity production
Production at the wellhead attributed to Questar ownership.
exploratory well
A well drilled into a previously untested geologic prospect to determine the presence of gas or oil.
finding costs
The sum of costs incurred for gas and oil exploration and development activities; including purchases of reserves in place, leasehold acquisitions, seismic, geological and geophysical, development and exploration drilling and asset retirement obligations for a given period, divided by the total amount of estimated net proved reserves added through discoveries, positive and negative revisions and purchases in place for the same period. The Company expresses finding costs in dollars per Mcfe averaged over a five-year period.
frac spread
The difference between the market value for NGL extracted from the gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids.
futures contract
An exchange-traded contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.
gal
U.S. gallon.
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 derivative commodity and interest-rate instruments to reduce financial exposure to commodity price and interest-rate volatility.
infill development drilling
Drilling wells between established producing wells; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons.
lease operating expenses
The expenses, usually recurring, which are incurred to operate the wells and equipment on a producing lease.
M
Thousand.
MM
Million.
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 and separated 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 those gross wells or acres.
net revenue interest
A share of production after all burdens, such as royalties and overriding royalties, have been deducted from the working interest. It is the percentage of production that each owner actually receives.

production replacement ratio
The production replacement ratio is calculated by dividing the net proved reserves added through discoveries, positive and negative revisions and purchases and sales in-place for a given period by the production for the same period, expressed as a percentage. The production replacement ratio is typically reported on an annual basis.
proved reserves
Those quantities of natural gas, crude oil, condensate and NGL on a net revenue interest basis, which geological and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions. See 17 C.F.R. Section 4-10(a)(2) for a complete definition.
proved developed reserves
Reserves that include proved developed producing reserves and proved developed nonproducing reserves. See 17 C.F.R. Section 4-10(a)(3).
proved developed producing reserves
Reserves expected to be recovered from existing completion intervals in existing wells.
proved undeveloped reserves
Reserves expected to be recovered from new wells on proved undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 4-10(a)(4).
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 an oil and gas 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 leased acreage 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
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.)
wet gas
Unprocessed natural gas that contains a mixture of heavier hydrocarbons including ethane, propane, butane and natural gasoline.
working interest
An interest in an oil and gas 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.
workover
Operations on a producing well to restore or increase production.

FORM 10-K
ANNUAL REPORT, 2006

PART I

ITEM 1. BUSINESS.

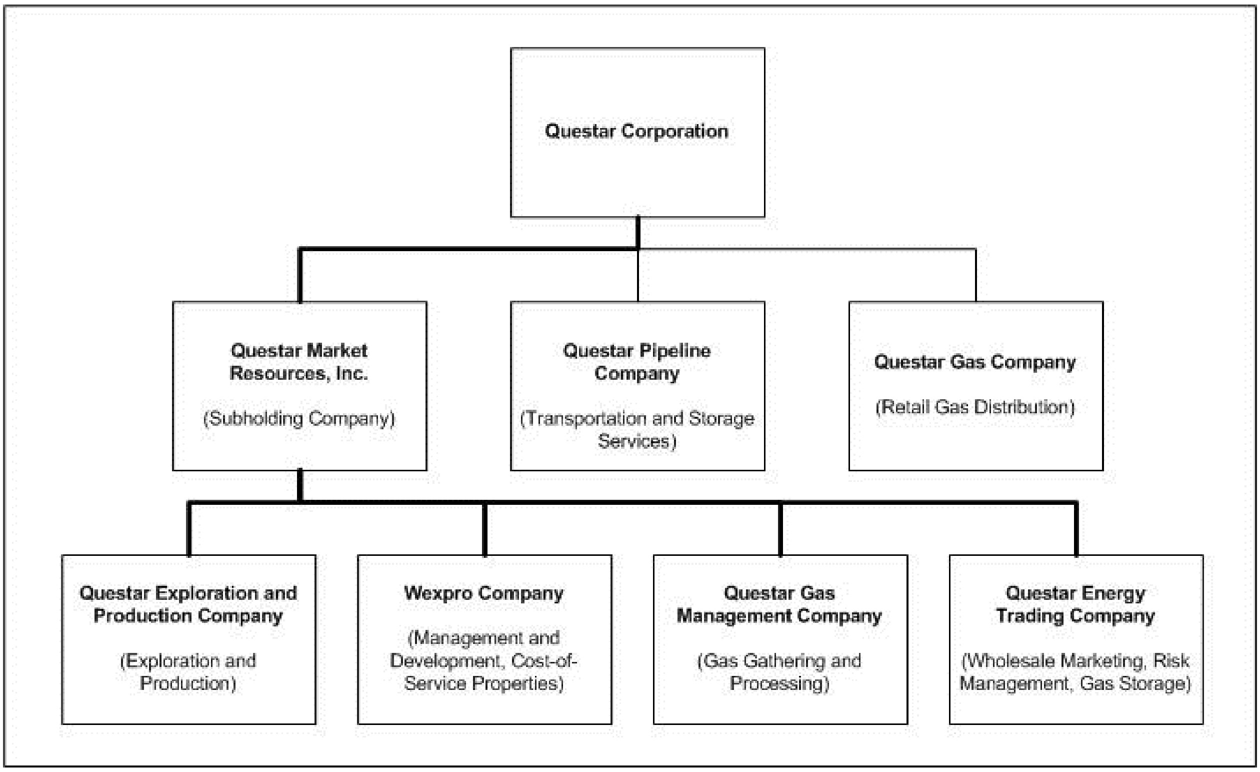
Nature of Business
Questar Market Resources, Inc. (Market Resources or the Company) is a natural gas-focused energy company, a wholly owned subsidiary of Questar Corporation (Questar) and Questar’s primary growth driver. Market Resources is a subholding company with four principal subsidiaries:

- Questar Exploration and Production Company (Questar E&P) acquires, explores for, develops and produces natural gas, oil, and NGL;
- Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for gas utility affiliate, Questar Gas;
- Questar Gas Management Company (Gas Management) provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and

· Questar Energy Trading Company (Energy Trading) markets equity and third-party gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

See Note 12 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for financial information concerning Market Resources lines of business that contribute 10% or more of consolidated revenues.

The corporate-organization structure and major subsidiaries are summarized below:



Questar E&P

Questar E&P operates in two core areas – the Rocky Mountain region of Wyoming, Utah and Colorado and the Midcontinent region of Oklahoma, Texas and Louisiana. Questar E&P has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming, in the Uinta Basin of Utah and in the Elm Grove area of northwestern Louisiana. Questar E&P continues to conduct exploratory drilling to determine the commerciality of its inventory of undeveloped leaseholds located primarily in the Rocky Mountain region. Questar E&P seeks to maintain geographical and geological diversity with its two core areas. Questar E&P 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 create a new core area.

Questar E&P reported 1,631.4 Bcfe of estimated proved reserves as of December 31, 2006. Approximately 81% of Questar E&P’s proved reserves, or 1,322.5 Bcfe, were located in the Rocky Mountain region of the United States, while the remaining 19%, or 308.9 Bcfe, were located in the Midcontinent region. Approximately 990.7 Bcfe of the proved reserves reported by Questar E&P at year-end 2006 were developed, while 640.7 Bcfe were proved undeveloped. The majority of the proved undeveloped reserves were associated with the Company’s Pinedale Anticline leasehold. Natural gas comprised about 90% of Questar E&P’s total proved reserves at year-end 2006. See Item 2 of Part I and Note 13 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for more information on Questar E&P’s proved reserves.

Questar E&P – Competition and Customers
Questar E&P faces competition in every part of its business, including the acquisition of reserves and leases. Its longer-term growth strategy depends, in part, on its ability to purchase reasonably priced reserves and develop them in a low-cost and efficient manner. Competition is particularly intense when prices are high, as has been the case in recent years.

Questar E&P, through Energy Trading, sells natural gas production to a variety of customers, including gas-marketing firms, industrial users and local-distribution companies. It regularly evaluates counterparty credit and may require financial guarantees from parties that fail to meet its credit criteria. Energy Trading sells equity crude-oil production to refiners, remarketers and other companies, including some with pipeline facilities near company producing properties. In the event pipeline facilities are not available, Energy Trading transports crude oil by truck to storage, refining or pipeline facilities.

Questar E&P – Regulation
Questar E&P operations are subject to various government controls and regulation at the federal, state and local levels. Questar E&P must obtain permits to drill and produce; maintain bonding requirements to drill and operate wells; submit and implement spill-prevention plans; and file notices relating to the presence, use, and release of specified contaminants incidental to gas and oil production. Questar E&P is also subject to various conservation matters, including the 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.

Most Questar E&P leases in the Rocky Mountain area are granted by the federal government and administered by federal agencies. Development of Pinedale leasehold acreage is subject to the terms of certain winter-drilling restrictions. In 2004, Market Resources worked with federal and state officials in Wyoming to obtain authorization for limited winter-drilling activities and has developed innovative measures, such as drilling multiple wells from a single location, to minimize the impact of its activities on wildlife and wildlife habitat. A Supplemental Environmental Impact Statement is currently being prepared by the Bureau of Land Management, (BLM) to consider expanded winter-drilling and completion operations on the Pinedale Anticline. The presence of wildlife and potential endangered species could limit access to public lands. Various wildlife species inhabit Market Resources leaseholds at Pinedale and in other areas. Current federal regulations restrict activities during certain times of the year on portions of Market Resources leaseholds due to wildlife activity and/or habitat.

Wexpro
Wexpro develops and produces gas and oil on certain properties for affiliate Questar Gas under the terms of a comprehensive agreement, the Wexpro Agreement. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19-20% on its investment in commercial wells and related facilities – adjusted for working capital and reduced for deferred income taxes and depreciation – its investment base. The term of the Wexpro Agreement coincides with the productive life of the gas and oil properties covered therein. Wexpro's investment base totaled $260.6 million at December 31, 2006. See Note 11 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for more information on the Wexpro Agreement.

Wexpro delivers natural gas production to Questar Gas at a price equal to Wexpro's cost-of-service. Cost-of-service gas satisfied 43% of Questar Gas supply requirements during 2006 at prices that were significantly lower than Questar Gas cost for purchased gas.

Wexpro gas and oil-development and production activities are subject to the same type of regulation as Questar E&P. In addition, the Utah Division of Public Utilities has oversight responsibility and retains an outside reservoir-engineering consultant and a financial auditor to assess the prudence of Wexpro's activities.

Wexpro owns oil-producing properties. Under terms of the Wexpro Agreement, revenues from crude-oil sales offset operating expenses and provide Wexpro with a return on its investment. Any remaining revenues, after recovery of expenses and Wexpro's return on investment, are divided between Wexpro (46%) and Questar Gas (54%).

Wexpro operations are contractually limited to a finite set of properties set forth in the Wexpro Agreement. Advances in technology (increased density drilling and multi-stage hydraulic fracture stimulation) have unlocked significant unexploited potential on many of the subject properties. Wexpro has identified over $1 billion of additional drilling opportunities that could support high single-digit to low double-digit growth in revenues and net income over the next five to ten years while delivering cost-of-service natural gas supplies to Questar Gas at prices competitive with alternative sources.

See Item 2 of Part I and Note 13 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for more information on the Company's cost-of-service proved reserves.

Gas Management
Gas Management provides natural gas-gathering and processing services to affiliates and third-party producers in the Rocky Mountain region. Gas Management owns 50% of Rendezvous Gas Services, LLC, (Rendezvous), a partnership that operates gas-gathering facilities in western Wyoming. Rendezvous gathers natural gas for Pinedale Anticline and Jonah field producers for delivery to various interstate pipelines. Gas Management also owns 38% of Uintah Basin Field Services. LLC (Field Services), a partnership that operates gas-gathering facilities in eastern Utah. Under a contract with Questar Gas, Gas Management also gathers cost-of-service volumes produced from properties operated by Wexpro.

Approximately 58% of Gas Management's 2006 revenues were derived from fee-based gathering and processing agreements. The remaining revenues were derived from natural gas processing margins that are in part exposed to the frac spread. To reduce processing margin risk, Gas Management has restructured many of its processing agreements with producers from "keep-whole" contracts to "fee-based" contracts. A keep-whole contract insulates producers from frac spread risk while a fee-based contract eliminates commodity price risk for the processing plant owner. To further reduce processing margin volatility associated with keep-whole contracts, Gas Management may also attempt to reduce processing margin risk with forward-sales contracts for NGL or hedge NGL prices and equivalent gas volumes with the intent to lock in a processing margin.

Energy Trading
Energy Trading markets natural gas, oil and NGL. It combines gas volumes purchased from third parties and equity production to build a flexible and reliable portfolio. As a wholesale marketing entity, Energy Trading concentrates on markets in the Rocky Mountains, Pacific Northwest and Midcontinent that are close to reserves owned by affiliates or accessible by major pipelines. It contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin, a large baseload-storage facility owned by affiliate Questar Pipeline. Energy Trading, through its subsidiary Clear Creek Storage Company, LLC, operates an underground gas-storage reservoir in southwestern Wyoming. Energy Trading uses owned and leased-storage capacity together with firm-transportation capacity to take advantage of price differentials and arbitrage opportunities.

Energy Trading uses derivatives to manage commodity price risk. Energy Trading primarily uses fixed-price swaps to secure a known price for a specific volume of production. Energy Trading does not engage in speculative hedging transactions. See Notes 1 and 6 to the consolidated financial statements included in Item 8 and in Item 7A of Part II of this Annual Report for additional information relating to hedging activities.

Environmental Matters
A discussion of Market Resources' environmental matters is included in Item 3 of Part I of this Annual Report.

Employees
At December 31, 2006, Market Resources had 679 employees compared with 601 a year earlier.

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.

The future price of natural gas, oil and NGL is unpredictable. Historically the price of natural gas, oil and NGL has been volatile and is likely to continue to be volatile in the future. Any significant or extended decline in commodity prices would impact the Company's future financial condition, revenues, results of operations, cash flows and rate of growth. Because approximately 90% of Market Resources proved reserves at December 31, 2006, were natural gas, the Company is substantially more sensitive to changes in natural gas prices than to changes in oil prices.

Market Resources 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, and NGL;
- regional price differences resulting from available pipeline transportation capacity or local demand;
- the level of imports of, and the price of, foreign natural gas, oil and NGL;
- domestic and global economic conditions;

- domestic political developments;
- weather conditions;
- domestic and foreign government regulations and taxes;
- political instability or armed conflict in oil and natural gas producing regions;
- conservation efforts;
- the price, availability and acceptance of alternative fuels;
- U.S. storage levels of natural gas, oil, and NGL;
- differing Btu content of gas produced and quality of oil produced.

Market Resources uses derivative instruments to manage exposure to uncertain prices. Market Resources uses financial contracts to hedge exposure to volatile 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 hedges commodity price exposure, it forgoes the benefits otherwise experienced if commodity prices increase. Market Resources believes its regulated businesses – interstate natural gas transportation and retail gas distribution – and its Wexpro subsidiary generate revenues that are not significantly sensitive to short-term fluctuations in commodity prices.

Market Resources enters into commodity price hedging arrangements with creditworthy counterparties (banks and industry participants) with a variety of credit requirements. Some contracts do not require the Company to post cash collateral, while others allow some amount of credit before requiring deposits of collateral for out-of-the-money hedges. The amount of credit available may vary depending on the credit ratings assigned to the Company's debt securities. A substantial increase in the price of natural gas, oil and/or NGL could result in the requirement to deposit large amounts of collateral with counterparties that could seriously impact the Company's cash liquidity. Additionally, a downgrade in the Company's credit ratings to sub-investment grade could result in the acceleration of obligations to hedge counterparties.

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 of the high-rate production decline profile of several of the Company's producing areas, substantial capital expenditures are required 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. Questar E&P'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 estimat ion process also involves economic assumptions relating to commodity prices, production costs, severance and other taxes, capital expenditures and remedial costs. Actual results most likely will vary from the estimates. Any significant variance could reduce the estimated future net revenues from proved reserves and the present value of those reserves.

Investors should not assume that the "standardized measure of discounted future net cash flows" from Questar E&P's proved reserves referred to in this Annual Report is the current market value of the estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from Questar E&P's proved reserves is based on prices and costs in effect on the date of the estimate, holding the prices constant throughout the life of the properties. 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 then current prices and costs may be significantly less than the current estimate.

Market Resources faces many operating risks to develop and produce its reserves. Drilling is a high-risk activity. Operating risks include: fire, explosions and blow-outs; unexpected drilling conditions such as abnormally pressured formations; abandonment costs; pipe, cement or casing failures; environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine 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 is customary in the gas and oil industry, the Company maintains insurance against some, but not all, of these potential risks and losses. Market Resources can not assure that insurance will be adequate to cover these losses or liabilities. Losses and liabilities arising from uninsured or underinsured events could have an adverse effect on the Company's financial condition and operations.

Shortages of oilfield equipment, services and qualified personnel could impact results of operations. The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased costs for drilling rigs, crews and associated supplies, equipment and services. These shortages or cost increases could impact profit margin, cash flow and operating results or restrict the ability to dri ll wells and conduct operations.

A significant portion of Market Resources production, revenue and cash flow are derived from assets that are concentrated in a geographical area. While geographic concentration of assets provides scope and scale that can reduce operating costs and provide other operating synergies, asset concentration does increase exposure to certain risks. Market Resources has extensive operations on the Pinedale Anticline and in the Greater Green River Basin of southwestern Wyoming. Any circumstance or event that negatively impacts the operations of Questar E&P, Wexpro or Gas Management in that area could materially reduce earnings and cash flow.

Gas and oil operations involve numerous risks that might result in accidents and other operating risks and costs. There are inherent operating risks and hazards in the Company's exploration and production, gas gathering and processing and gas transportation operations, such as fires, earthquakes, leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of these risks and 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 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 could further result in loss of service available to the Company's customers. Such circumstances could adversely impact the Company's ability to meet contractual obligations and retain customers.

Market Resources is subject to complex regulations on many levels. The Company is subject to federal, state and local 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 that 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.

Market Resources must comply with numerous and complex regulations governing activities on federal and state lands in the Rocky Mountain region, notably the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act. Federal and state agencies frequently impose conditions on the Company's activities. These restrictions have become more stringent over time and can limit or prevent exploring for, finding and producing natural gas and oil on the Company's Rockies leasehold. Certain environmental groups oppose drilling on some of Market Resources federal and state leases.

Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to 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, each Native American tribe is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Finally, lessees and operators conducting operations on tribal lands are generally subject to the Native Ameri can 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, oil and transportation operations on such lands.

Federal Energy Regulatory Commission (FERC) regulates interstate transportation of natural gas. Market Resources natural gas storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The FERC has authority to: set rates for natural gas transportation, storage and related services; set rules governing business relationships between the pipeline subsidiary and its affiliates; approve new pipeline and storage-facility construction; and establish policies and procedures for accounting, purchase, sale, abandonment and other activities. FERC policies may adversely affect Market Resources profitability. The FERC also has various affiliate rules that may cause the Company to incur additional costs of compliance.

Market Resources is dependent on bank credit facilities and continued access to capital markets to successfully execute its operating strategies. Market Resources also relies on access to short-term commercial paper markets. The Company is dependent on these capital sources to provide financing for certain projects. The availability and cost of these credit sources is cyclical, and these capital sources may not remain available or the Company may not be able to obtain money at a reasonable cost in the future. All Market Resources bank loans are floating-rate debt. From time to time the Company may use interest rate derivatives to fix the rate on a portion of its variable rate debt. The interest rates on bank loans are tied to debt credit ratings of Market Resources and its subsidiaries published by Standard & Poor's and Moody's. A downgrade of credit ratings could increase the interest cost of debt and decrease future availability of money from banks and other sourc es. Management believes it is important to maintain investment grade credit ratings to conduct the Company's businesses, but may not be able to keep investment grade ratings.

There is no promise of continuing relationships with Questar. Market Resources is a wholly owned subsidiary of Questar and its goals and strategies are important to Questar. Questar, however, offers no explicit promise of continued ownership or of the availability of capital going forward. The Company's ability to receive future equity and debt capital from its parent also depends on Questar's ability to access capital markets on reasonable terms. Market Resources subsidiaries benefit from business transactions with affiliated companies. Gas Management and Wexpro have long-term agreements to gather and develop reserves owned by affiliate Questar Gas. All transactions are on a competitive market basis or under contracts approved by regulatory agencies and the courts, but such business relationships may not continue in the future.

General economic and other conditions impact Market Resources results. Market Resources results may also be negatively affected by: changes in general 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 Market Resources.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Questar E&P and Cost-of-Service

Reserves – Questar E&P

The following table sets forth Questar E&P's estimated proved reserves, the estimated future net revenues from the reserves and the standardized measure of discounted net cash flows as of December 31, 2006. The estimates were collectively prepared by Ryder Scott Company, LP, H. J. Gruy and Associates, Inc. and Netherland, Sewell & Associates, Inc., independent reservoir-engineering consultants. Questar E&P does not have any long-term supply contracts with foreign governments or reserves of equity investees of subsidiaries with a significant minority interest. At December 31, 2006, Questar E&P was the operator of approximately 82% of its estimated proved reserves. All reported reserves are located in the United States.

Estimated proved reserves	
Natural gas (Bcf)	**1,461.2**
Oil and NGL (MMbbl)	**28.4**
Total proved reserves (Bcfe)	**1,631.4**
Proved developed reserves (Bcfe)	**990.7**
Estimated future net revenues before future income taxes (in millions) (1)	**$4,825.2**
Standardized measure of discounted net cash flows (in millions) (2)	**$1,567.8**

(1) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, using average year-end 2006 prices of $4.47 per Mcf for natural gas and $51.49 per bbl for oil and NGL combined, net of estimated production and development costs (but excluding the effects of general and administrative expenses; debt service; depreciation, depletion and amortization; and income tax expense).

(2) The standardized measure of discounted future net cash flows prepared by the Company represents the present value of estimated future net revenues after income taxes, discounted at 10%.

Estimates of proved reserves and future net revenues are made at year-end, using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the remaining life of the properties (except to the extent a contract specifically provides for escalation). Year-end prices do not include the effect of hedging. Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating natural gas and oil reserves and their estimated values, including many factors beyond the control of the Company.

Questar E&P's reserve statistics for the years ended December 31, 2004 through 2006, are summarized below:

		Proved Gas and Oil Reserves	
Year	Year End Reserves (Bcfe)	Annual Production (Bcfe)	Reserve Life (Years)
2004	1,434.0	103.5	13.9
2005	1,480.4	114.2	13.0
2006	**1,631.4**	**129.6**	**12.6**

In 2006, gas and oil reserves increased 10%, after production and sales of producing properties, to 1,631.4 Bcfe versus a 3% increase in 2005 to 1,480.4 Bcfe. Questar E&P's production replacement ratio was 217% in 2006 and 141% in 2005. Net reserve additions, revisions, purchases and sales in place totaled 280.7 Bcfe in 2006 and 160.6 Bcfe in 2005. Questar E&P's five-year average finding cost of proved reserves per Mcfe was $1.53 in 2006, $1.08 in 2005 and $0.83 in 2004.

Finding costs measure the costs of finding, developing and acquiring new proved reserves. The production replacement ratio measures company success at replacing production during a specific period. If the production replacement ratio is greater than 100%, the Company added or replaced more reserves than it produced for the same period.

Questar E&P proved reserves by major operating areas at December 31, 2006 and 2005 follow:

	2006		2005	
	(Bcfe)	**(% of total)**	(Bcfe)	(% of total)
Pinedale Anticline	**931.9**	**57%**	780.0	53%
Uinta Basin	**248.3**	**15%**	254.9	17%
Rockies Legacy	**142.3**	**9%**	144.4	10%
Rocky Mountains Total	**1,322.5**	**81%**	1,179.3	80%
Midcontinent	**308.9**	**19%**	301.1	20%
Questar E&P Total	**1,631.4**	**100%**	1,480.4	100%

Reserves – Cost-of-Service

The following table sets forth estimated cost-of-service proved natural gas reserves, which Wexpro develops and produces for Questar Gas under the terms of the Wexpro Agreement; and Wexpro proved oil reserves. The estimates of cost-of-service proved reserves were made by Wexpro reservoir engineers as of December 31, 2006. All reported reserves are located in the United States.

Estimated cost-of-service proved reserves	
Natural gas (Bcf)	**620.6**
Oil (MMbbl)	**4.4**
Total proved reserves (Bcfe)	**647.0**
Proved developed reserves (Bcfe)	**458.2**

The gas reserves operated by Wexpro are delivered to Questar Gas at cost of service. Net income from oil properties remaining after recovery of expenses and Wexpro contractual return on investment under the settlement agreement is divided between Wexpro and Questar Gas. Therefore, SEC guidelines with respect to standard economic assumptions are not applicable. The SEC anticipated such potential difficulty and provides that companies may give appropriate recognition to differences arising because of the effect of the ratemaking process. Accordingly, Wexpro reservoir engineers used a minimum producing rate or maximum well-life limit to determine the ultimate quantity of reserves attributable to each well.

Reference should be made to Note 13 of the consolidated financial statements included in Item 8 of Part II of this Annual Report for additional information pertaining to both Questar E&P proved reserves and the Company's cost-of-service reserves as of the end of each of the last three years.

In addition, to this filing, Questar E&P and Wexpro will each file estimated reserves as of December 31, 2006, with the Energy Information Administration in the Department of Energy on Form EIA-23. Although the companies use the same technical and economic assumptions when they prepare the EIA-23, they are obligated to report reserves for all wells they operate, not for all wells in which they have an interest, and to include the reserves attributable to other owners in such wells.

Production

The following table sets forth the net production volumes, the average sales prices per Mcf of natural gas, per bbl of oil and NGL produced, and the lifting cost per Mcfe for the years ended December 31, 2006, 2005 and 2004. Lifting costs include labor, repairs, maintenance, materials, supplies and workovers, administrative costs of production offices, insurance and property and severance taxes.

	Year Ended December 31,		
	2006	2005	2004
Questar E&P			
Volumes produced and sold			
Natural gas (Bcf)	**113.9**	100.0	89.8
Oil and NGL (MMbbl)	**2.6**	2.4	2.3
Total production (Bcfe)	**129.6**	114.2	103.5
Average realized price (including hedges)			
Natural gas (per Mcf)	**$ 6.00**	$ 5.18	$ 4.18
Oil and NGL (per bbl)	**49.12**	41.54	30.97
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.57**	$ 0.54	$ 0.50
Production taxes	**0.45**	0.60	0.46
Total lifting costs	**$ 1.02**	$ 1.14	$ 0.96
Cost-of-Service			
Volumes produced			
Natural gas (Bcf)	**38.8**	40.0	38.8
Oil and NGL (MMbbl)	**0.4**	0.4	0.4

Productive Wells
The following table summarizes Market Resources productive wells (including cost-of-service wells) as of December 31, 2006. All of these wells are located in the United States.

	Gas	Oil	Total
Gross	**4,633**	**966**	**5,599**
Net	**2,065.6**	**456.2**	**2,521.8**

Although many Market Resources wells produce both gas and oil, a well is categorized as either a gas or an oil well based upon the ratio of gas to oil produced. Each gross well completed in more than one producing zone is counted as a single well. At the end of 2006, there were 88 gross wells with multiple completions.

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

Leasehold Acres
The following table summarizes developed and undeveloped-leasehold acreage in which Market Resources owns a working interest as of December 31, 2006. "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 Market Resources interest is limited to royalty, overriding-royalty and other similar interests. All leasehold acres are located in the U.S.

Leasehold Acreage – December 31, 2006

	Developed (1)		Undeveloped (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
			(in acres)			
Arizona			480	450	480	450
Arkansas	32,049	10,310	3	1	32,052	10,311
California	25	2	1,293	192	1,318	194
Colorado	143,967	99,540	169,367	81,470	313,334	181,010
Idaho			44,175	10,643	44,175	10,643
Illinois	172	39	14,207	3,949	14,379	3,988
Indiana			1,890	702	1,890	702
Kansas	30,302	13,396	16,880	3,963	47,182	17,359
Kentucky			17,323	6,669	17,323	6,669
Louisiana	13,242	12,065	1,553	999	14,795	13,064
Michigan	89	8	6,240	1,262	6,329	1,270
Minnesota			313	104	313	104
Mississippi	2,904	1,798	965	398	3,869	2,196
Montana	19,829	8,374	299,847	51,507	319,676	59,881
Nevada	320	280	680	543	1,000	823
New Mexico	97,531	68,858	25,333	5,315	122,864	74,173
North Dakota	4,635	546	146,364	21,757	150,999	22,303
Ohio			202	43	202	43
Oklahoma	1,519,727	271,962	98,956	54,345	1,618,683	326,307
Oregon			43,869	7,671	43,869	7,671
South Dakota			204,398	107,829	204,398	107,829

Texas	147,467	61,167	70,761	53,977	218,228	115,144
Utah	128,173	104,340	288,313	148,611	416,486	252,951
Washington			26,631	10,149	26,631	10,149
West Virginia	969	115			969	115
Wyoming	260,030	161,295	345,692	227,857	605,722	389,152
Grand Total	2,401,431	814,095	1,825,735	800,406	4,227,166	1,614,501

(1) Developed acreage is acreage spaced or assignable 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 obtained from the acreage subject to the lease prior to that date. In that event, the lease will 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	Acres Expiring	
	Gross	Net
12 months ending December 31,	(in acres)	
2007	70,574	53,248
2008	80,408	49,310
2009	67,956	43,227
2010	36,599	17,008
2011 and later	175,963	159,381

Drilling Activity

The following table summarizes the number of development and exploratory wells drilled by Market Resources, including the cost-of-service wells drilled by Wexpro, during the years indicated.

	Year Ended December 31,					
	Productive			Dry		
	2006	2005	2004	**2006**	2005	2004
Net Wells Completed						
Exploratory	**0.9**	6.1	4.7	**5.2**	1.5	
Development	**185.6**	165.2	156.0	**4.6**	7.4	6.6
Gross Wells Completed						
Exploratory	**2**	9	9	**11**	4	
Development	**408**	370	322	**18**	15	13

Gas Management

Gas Management owns 1,474 miles of gathering lines in Utah, Wyoming, and Colorado. In conjunction with these gathering facilities, Gas Management owns compression facilities, field-dehydration and measuring systems. Gas Management is a 50% partner in Rendezvous, which owns an additional 229 miles of gathering lines and associated field equipment and is a 38% partner in Field Services which owns 65 miles of gathering lines and associated field equipment.

Gas Management owns processing plants that have an aggregate capacity of 440 MMcf of unprocessed natural gas per day.

Energy Trading

Energy Trading, through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir in southwestern Wyoming.

ITEM 3. LEGAL PROCEEDINGS.

Market Resources 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 Market Resources financial position. An accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. 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.

Pinedale Unit Net Profits Interest Litigation

In March 2006, Doyle Hartman and other alleged stakeholders (collectively the "Hartman Group") filed a declaratory judgment action against Questar E&P, Wexpro and others in Sublette County District Court, Wyoming (Case No. 2006-6843) claiming a 5% net profits interest (NPI) in Pinedale leasehold interests. The Hartman Group seeks a declaratory judgment that the NPI burdens leases committed to the original Pinedale Unit regardless of whether the leases and lands have been eliminated from the Pinedale Unit by contraction and termination of that Unit. The defendants have denied the allegations and filed counterclaims for declaratory judgment and quiet title. In January 2007, the court dismissed a declaratory judgment action previously filed by Questar E&P and Wexpro in order to have all claims and counterclaims consolidated in a single case (Case No. 2006-6843). The court also granted the Hartman Group leave to amend its complaint which amended complaint alleges claims fo r declaratory judgment, accounting, damages for breach of contract, breach of royalty payment obligations, slander of title, breach of the duty of good faith and fair dealing, rescission, constructive trust and conversion. The Hartman Group has also filed motions for partial summary judgment which are pending with the court. The defendants will be filing a response to the amended complaint and motions for summary judgment.

Grynberg Cases

Questar affiliates are involved in various pending lawsuits filed by Jack Grynberg, an independent producer. In *United States ex rel. Grynberg v. Questar Corp.*, Civil No. 99-MD-1604, consolidated as *In re Natural Gas Royalties Qui Tam Litigation*, Consolidated Case MDL No. 1293 (D. Wyo.), Grynberg filed *qui tam* claims against Questar under the federal False Claims Act that were substantially similar to other cases filed against other industry pipelines and their affiliates. The cases were consolidated for discovery and pre-trial motions in Wyoming's federal district court. The cases involve allegations of industry-wide mismeasurement of natural gas quantities on which royalty payments are due the federal government.

The defendants filed a motion contending that the court has no jurisdiction over the case because Grynberg cannot satisfy the statutory requirements for jurisdiction. The defendants argued that Grynberg's allegations were publicly disclosed prior to the filing of his complaint and that Grynberg is not the "original source" of the information on which the allegations are based. By order dated October 20, 2006, the district court granted defendants motion and dismissed all of Grynberg's claims against all the defendants for lack of jurisdiction. The judge found that Grynberg was not the "original source" and therefore could not bring the action. Grynberg has appealed the case to the U.S. Tenth Circuit Court of Appeals.

In *Grynberg and L & R Exploration Venture v. Questar Pipeline Co.*, Civil No. 97CV0471 (D. Wyo.), Grynberg brought breach of contract claims, statutory claims and fraud claims against Questar entities related to a certain gas purchase contract for the purchase of gas produced from wells located in Wyoming. In December, 1998, the federal district court granted Questar's motion for partial summary judgment on a contract termination issue and in June 2001, the court granted partial summary judgment dismissing the antitrust claims from the case. By order dated September 12, 2006, the judge also dismissed the fraud claims and ratable-take claims. The breach of contract claims are the only issues remaining to be decided. Grynberg has appealed the case to the U.S. Tenth Circuit Court of Appeals.

Kansas Cases

Energy Trading is a named defendant in cases pending in a Kansas state district court, *Price v. Gas Pipelines*, No. 99 C 30 (Dist. Ct. Kan.) and *Price v. El Paso Entities*, No. 03 C 23 (Dist. Ct. Kan.). These cases are similar to the cases filed by Grynberg, but the allegations of a conspiracy by the pipeline industry to set standards that result in the systematic undermeasurement of natural gas volumes and resulting underpayment of royalties are made on behalf of private lessors rather than on behalf of the federal government. The purported class involves all royalty owners of production from private land in Kansas, Wyoming and Colorado. Energy Trading opposes certification of the class and contends that it is not engaged in any gas measurement activities in Kansas. A hearing on plaintiffs' motion to certify the class was held on April 1, 2005. The court has not issued a ruling in the case.

Environmental Claims

In 2004, the Environmental Protection Agency (EPA) issued two separate compliance orders alleging that Gas Management did not comply with regulatory requirements adopted to enforce the federal Clean Air Act. Both orders involved facilities in the Uinta Basin of eastern Utah that were purchased by Questar E&P in mid-2001. Gas Management believes it is operating the facilities and filing necessary reports in compliance with regulatory requirements; however, the EPA contends such facilities are located within Indian Country and are subject to additional Clean Air Act requirements not applicable to non-Indian Country lands administered by the state of Utah. As a consequence, EPA has broadened its allegations to include additional potential ongoing violations of the Clean Air Act for the referenced facilities. Other Gas Management facilities in the Uinta Basin have been added to the civil penalty discussions with the EPA, with similar allegations&n bsp;of Clean Air Act violations. These potential violations will likely result in civil penalties of an unknown and undetermined amount in excess of $100,000.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

The Company, as a wholly owned subsidiary of a reporting company under the Act, is entitled to omit the information in this Item.

PART II

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

All of the Company's outstanding shares of common stock, $1.00 par value, are owned by Questar. Information concerning the dividends paid on such stock and the ability to pay dividends is reported in the Statements of Consolidated Shareholder's Equity and the notes accompanying the consolidated financial statements included in Item 8 of Part II of this Annual Report.

ITEM 6. SELECTED FINANCIAL DATA.

The Company, as a wholly owned subsidiary of a reporting company under the Act, is entitled to omit the information in this Item.

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

SUMMARY

Market Resources net income increased 38% in 2006 compared to 2005 and 56% in 2005 over 2004. Primary factors for the higher income were increases in natural gas production, higher realized natural gas, oil and NGL prices, higher gas processing and gas gathering margins, and increases in the Wexpro investment base.

	Year Ended December 31			Change	Change
	2006	2005	2004	**2006 v. 2005**	2005 v. 2004
	(in millions, except per-share amounts)				
NET INCOME					
Questar E&P	**$253.9**	$172.8	$108.2	**$81.1**	$64.6
Wexpro	**50.0**	43.7	35.3	**6.3**	8.4
Gas Management	**42.6**	35.7	21.0	**6.9**	14.7
Energy Trading	**9.6**	6.0	0.9	**3.6**	5.1
Market Resources total	**$356.1**	$258.2	$165.4	**$97.9**	$92.8

RESULTS OF OPERATION

Market Resources operates through four principal subsidiaries. Questar E&P acquires, explores for, develops and produces natural gas, oil, and NGL; Wexpro manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas;

Gas Management provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and Energy Trading markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned limited liability company, Clear Creek Storage Company, LLC, owns and operates an underground natural gas-storage reservoir.

Consolidated Results

Market Resources reported $356.1 million of net income for 2006 compared with $258.2 million in 2005, a 38% increase, and $165.4 million in 2004. Operating income increased $160.8 million, or 38%, in the 2006 to 2005 comparison due primarily to increased natural gas production and higher realized prices at Questar E&P, an increased investment base at Wexpro, increased gas-processing plant margins at Gas Management and a net gain from asset sales. Following is a summary of Market Resources financial and operating results:

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
OPERATING INCOME			
Revenues			
Natural gas sales	**$ 684.0**	$ 517.6	$ 375.2
Oil and NGL sales	**149.6**	118.6	86.4
Cost-of-service gas operations	**148.6**	133.2	116.7
Energy marketing	**668.7**	902.8	506.6
Gas gathering, processing and other	**184.9**	156.0	100.4
Total revenues	**1,835.8**	1,828.2	1,185.3
Operating expenses			
Energy purchases	**652.6**	888.3	499.7
Operating and maintenance	**180.4**	158.6	113.8
General and administrative	**69.2**	54.6	49.6
Production and other taxes	**89.4**	102.2	73.2
Depreciation, depletion and amortization	**235.0**	173.8	142.7
Exploration	**34.4**	11.5	9.2
Abandonment and impairment	**7.6**	7.9	15.8
Wexpro Agreement – oil-income sharing	**5.5**	6.1	4.7
Total operating expenses	**1,274.1**	1,403.0	908.7
Net gain from asset sales	**25.2**	0.9	0.3
Operating income	**$ 586.9**	$ 426.1	$ 276.9
OPERATING STATISTICS			
Questar E&P production volumes			
Natural gas (Bcf)	**113.9**	100.0	89.8
Oil and NGL (MMbbl)	**2.6**	2.4	2.3
Total production (Bcfe)	**129.6**	114.2	103.5
Average daily production (MMcfe)	**355.2**	312.9	282.8
Questar E&P average realized price, net to the well (including hedges)			
Natural gas (per Mcf)	**$6.00**	$5.18	$4.18
Oil and NGL (per bbl)	**$49.12**	$41.54	$30.97
Wexpro investment base at December 31, net			

of depreciation and deferred income taxes (millions)	**$260.6**	$206.3	$182.8
Natural gas processing volumes			
NGL sales volumes (MMgal)	**88.1**	88.4	55.5
Processing fee based (in millions of MMBtu)	**120.4**	75.5	29.8
Natural gas processing revenues			
NGL sales price (per gal)	**$0.88**	$0.77	$0.65
Processing fee based (per MMBtu)	**$0.14**	$0.15	$0.13
Natural gas gathering volumes (in millions of MMBtu)			
For unaffiliated customers	**153.9**	145.0	128.7
For Questar Gas	**42.2**	43.1	39.0
For other affiliated customers	**78.0**	68.9	57.0
Total gathering	**274.1**	257.0	224.7
Gathering revenue (per MMBtu)	**$0.29**	$0.25	$0.22
Natural gas and oil marketing volumes (MMdthe)			
For unaffiliated customers	**118.3**	118.5	91.2
For affiliated customers	**102.0**	91.8	82.5
Total marketing	**220.3**	210.3	173.7

Questar E&P

Questar E&P, a Market Resources subsidiary that conducts natural gas and oil exploration, development and production, reported net income of $253.9 million in 2006, up 47% from $172.8 million in 2005 and $108.2 million in 2003. The increase was driven by a combination of higher realized natural gas, oil and NGL prices and increased gas, oil and NGL production volumes.

Questar E&P reported production volumes increased to 129.6 Bcfe in 2006, a 13% increase compared to 2005. Natural gas is Questar E&P’s primary focus. On an energy equivalent basis, natural gas comprised approximately 88% of Questar E&P 2006 production. A comparison of natural gas-equivalent production by region is shown in the following table:

	Year Ended December 31,			Change	Change
	2006	2005	2004	**2006 vs. 2005**	2005 vs. 2004
			(in Bcfe)		
Pinedale Anticline	**39.5**	33.2	23.5	**6.3**	9.7
Uinta Basin	**25.1**	25.6	24.8	**(0.5)**	0.8
Rockies Legacy	**18.3**	16.7	18.0	**1.6**	(1.3)
Rocky Mountain total	**82.9**	75.5	66.3	**7.4**	9.2
Midcontinent	**46.7**	38.7	37.2	**8.0**	1.5
Total Questar E&P	**129.6**	114.2	103.5	**15.4**	10.7

Questar E&P production from the Pinedale Anticline in western Wyoming grew 19% to 39.5 Bcfe in 2006 and comprised 30% of Questar E&P total production in the 2006 period compared to 33.2 Bcfe and 29% of 2005 production. Questar E&P completed 51 new wells during 2006 and 40 new wells at Pinedale during 2005.

In the Uinta Basin of eastern Utah, Questar E&P production decreased 2% to 25.1 Bcfe in 2006 compared to a year ago. Production increased 3% to 25.6 Bcfe in 2005 compared to 24.8 Bcfe in 2004 despite production constraints related to third quarter construction and maintenance on an interstate pipeline.

Production from Questar E&P Rocky Mountain “Legacy” properties increased 10% to 18.3 Bcfe in 2006 compared to a year ago. Excluding a one-time adjustment of 0.7 Bcfe, Legacy 2006 production was 17.6 Bcfe, an increase of 5% over the 2005 period driven by the company's emerging gas play in the Vermillion Basin. Legacy assets include all Questar E&P Rocky Mountain region properties except the Pinedale Anticline and the Uinta Basin. Production during the 2005 period was negatively impacted by normal field decline, seasonal restrictions that limit access to leases and wells during the winter months, payout of a high-volume well that reduced the company's working interest and mechanical problems that delayed completion of a new well in the Vermillion Basin.

In the Midcontinent, production grew 21% to 46.7 Bcfe in 2006, driven by ongoing infill-development drilling in the Elm Grove field in northwestern Louisiana.

Questar E&P also benefited from higher realized prices for natural gas, oil and NGL. In 2006, the weighted average realized natural gas price for Questar E&P (including the impact of hedging) was $6.00 per Mcf compared to $5.18 per Mcf for the same period in 2005, a 16% increase. Realized oil and NGL prices in 2006 averaged $49.12 per bbl, compared with $41.54 per bbl during the prior year period, an 18% increase. A regional comparison of average realized prices including hedges is shown in the following table:

	Year Ended December 31,			Change	Change
	2006	2005	2004	**2006 vs. 2005**	2005 vs. 2004
Natural gas (per Mcf)					
Rocky Mountains	**$5.73**	$5.01	$3.95	**$0.72**	$1.06
Midcontinent	**6.47**	5.49	4.57	**0.98**	0.92
Volume-weighted average	**6.00**	5.18	4.18	**0.82**	1.00
Oil and NGL (per bbl)					
Rocky Mountains	**$46.62**	$42.08	$30.10	**$4.54**	$11.98
Midcontinent	**54.93**	40.25	32.98	**14.68**	7.27
Volume-weighted average	**49.12**	41.54	30.97	**7.58**	10.57

Approximately 70% in 2006 and 83% in 2005 of Questar E&P gas production was hedged or pre-sold. Hedging increased 2006 gas revenues by $53.7 million and reduced 2005 gas revenues by $173.9 million. Approximately 78% in 2006 and 70% in 2005 of Questar E&P oil production was hedged or pre-sold. Oil hedges reduced revenues $19.6 million in 2006 and $24.8 million in 2005.

Questar E&P may hedge up to 100 percent of forecasted production from proved reserves to lock in acceptable returns on invested capital and to protect returns, cash flow and net income from a decline in commodity prices. During 2006, Questar E&P continued to take advantage of high natural gas and oil prices to hedge additional production through 2008. In 2006, the company began using basis-only swaps to protect cash flows and net income from widening natural gas-price basis differentials that may result from capacity constraints on regional gas pipelines. Derivative positions as of December 31, 2006, are summarized in Part II of Item 7A of this Annual Report.

Questar E&P production costs (the sum of depreciation, depletion and amortization expense, lease operating expense, general and administrative expense, allocated-interest expense and production taxes) per Mcfe of production increased 6% to $2.99 per Mcfe in 2006 versus $2.83 per Mcfe in 2005 and $2.51 in 2004. Questar E&P production costs are summarized in the following table:

	Year Ended December 31,			Change	Change
	2006	2005	2004	**2006 vs. 2005**	2005 vs. 2004
			(per Mcfe)		
Depreciation, depletion and amortization	**$1.43**	$1.18	$1.04	**$0.25**	$0.14
Lease operating expense	**0.57**	0.54	0.50	**0.03**	0.04
General and administrative expense	**0.33**	0.30	0.30	**0.03**	
Allocated interest expense	**0.21**	0.21	0.21		
Production taxes	**0.45**	0.60	0.46	**(0.15)**	0.14
Total production costs	**$2.99**	$2.83	$2.51	**$0.16**	$0.32

Depreciation, depletion and amortization expense rose due to higher costs for drilling, completion and related services, increased cost of steel casing, other tubulars and wellhead equipment, and the ongoing depletion of older, lower-cost reserves. Per unit lease operating expense increased due to increased costs of materials and consumables and higher well workover costs. General and administrative expenses increased due to higher labor costs and an increase in the allowance for doubtful accounts.

Production taxes per unit decreased with lower sales prices on natural gas, increased incentive tax credits related to well drilling and production enhancement projects, and adjustments to prior estimates. Most production taxes are based on a fixed percentage of commodity sales prices.

Questar E&P exploration expense increased $23.3 million in 2006 compared to 2005. The increase was primarily due to expenses for unsuccessful exploratory wells. Questar E&P plugged and abandoned the deep exploratory portion of the Stewart Point 15-29 well on the Pinedale Anticline after failing to establish commercial production in the Hilliard and Rock Springs formations. The company recorded a $10.0 million charge related to abandonment of the deep portion of the well, which was subsequently re-completed as a commercial well in the Lance Pool. Exploration expense increased $1.9 million in 2005 compared to 2004. The expense increase was due to increased exploratory seismic acquisition expenditures in the Midcontinent and Uinta Basin. Abandonment and impairment expense decreased $0.1 million in 2006 compared to 2005 and declined $5.3 million in 2005 compared to 2004. The 2004 amount included $2.3 million of expense due to a well with collapsed casing and $3.3 million for an aban doned coal bed methane project.

In 2006, Questar E&P sold certain proved reserves and undeveloped leasehold interests in western Colorado and recognized a pre-tax gain of $22.7 million. For income tax purposes, the company structured the sale of the Colorado properties and the 2006 acquisition of certain Louisiana properties to qualify as a reverse like-kind exchange of property under Section 1031 of the Internal Revenue Code of 1986, as amended.

Pinedale Anticline Drilling Activity
As of December 31, 2006, Market Resources (including both Questar E&P and Wexpro) operated and had working interest in 195 producing wells on the Pinedale Anticline compared to 144 and 104 at year-end 2005 and 2004, respectively. Of the 195 producing wells, Questar E&P has working interests in 173 wells, overriding royalty interests only in an additional 21 Wexpro-operated wells, and no interest in one well operated by Wexpro. Wexpro has working interests in 66 of the 195 producing wells.

In 2005, the Wyoming Oil and Gas Conservation Commission approved 10-acre-density drilling for Lance Pool wells on about 12,700 acres of Market Resources 18,208 acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the currently estimated productive limits of Market Resources core acreage in the field. With 10-acre-density drilling, the company currently believes that up to 932 wells will be required to fully develop the Lance Pool on its acreage.

Uinta Basin
During 2006, the company drilled or participated in 65 Wasatch and Upper Mesaverde gas wells, four horizontal and one vertical Green River Formation oil wells, and four deeper Blackhawk, Mancos and Dakota formations gas wells on its core acreage block.

As of December 31, 2006, Questar E&P had drilled five wells in the Flat Rock and Wolf Flat areas in the southern portion of the Uinta Basin, including two wells on its 12,577 gross acre Ute Tribe Exploration and Development Agreement lands and three wells on its State of Utah leasehold, and was drilling another well at year end.

Rockies Legacy
In the Vermillion Basin on the southwestern Wyoming-northwestern Colorado state line, Market Resources continues to evaluate the potential of several formations under the company’s 146,000 net leasehold acres. As of December 31, 2006, the company had recompleted two older wells, drilled and completed 13 new wells, and two were waiting on completion. The targets are the Baxter Shale, which extends across a 3,000-3,500 foot gross interval from about 9,500 feet deep to about 13,000 feet deep on most of the company’s leasehold in the basin, and the deeper Frontier and Dakota tight-sand formations at depths down to 14,000 feet.

Midcontinent
Questar E&P continued a two-rig infill-development project in the Elm Grove field in northwest Louisiana as it operated or participated in eight new wells that were completed in the fourth quarter of 2006. The company participated in the completion of 36 wells in Elm Grove field in 2006. In 2006, Questar E&P also acquired interests in 48 producing wells in nine spacing units in

the Elm Grove field. The acquisition provides Questar E&P initial or additional working interest in approximately 75 undrilled locations.

Wexpro
Wexpro, a Market Resources subsidiary that develops and produces cost-of-service reserves for Questar Gas, reported net income of $50.0 million, in 2006 compared to $43.7 in 2005, a 14% increase and $35.3 million in 2004. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19% to 20% on its investment in commercial wells and related facilities – adjusted for working capital and reduced for deferred income taxes and depreciation (investment base). Wexpro investment base at December 31, 2006, was $260.6 million, an increase of $54.3 million or 26%.

Gas Management
Gas Management, Market Resources gas-gathering and processing-services business, grew net income 19% to $42.6 million in 2006 from $35.7 million in 2005 and $21.0 million in 2004. Gas processing plant margin grew 72% from $24.3 million in 2005 to $41.7 million in 2006. Gathering volumes increased 17.1 million MMBtu to 274.1 million MMBtu in 2006 due primarily to expanding Pinedale production and new projects serving third parties in the Uinta Basin. Total gathering margins increased 9% despite increased start-up costs associated with the Pinedale liquids-gathering and transportation facilities.

To reduce processing margin risk, Gas Management has restructured a number of its processing agreements with producers from “keep-whole” contracts to “fee-based” contracts. A keep-whole contract protects producers from frac spread risk while fee-based contracts eliminate commodity-price risk for the plant owner. In 2006, revenues from keep-whole contracts benefited from a 13% increase in realized NGL sales prices versus the prior-year period. Revenues from fee-based contracts were impacted by a 59% increase in processing volumes offset by a $0.01 decrease in the average rate charged per MMBtu processed compared with 2005. To further reduce margin volatility associated with keep-whole contracts, Gas Management began managing NGL price risk in 2004 by using forward-sales contracts. Forward sales contracts increased NGL revenues by $0.7 million in 2006 and decreased NGL revenues $1.0 million in 2005.

Income before income tax from Gas Management’s 50% interest in Rendezvous was $7.0 million for 2006 compared to $7.2 million in 2005 and $5.0 million in 2004. Rendezvous provides gas gathering services for the Pinedale and Jonah producing areas. Gas Management continues to invest in additional gas gathering and processing and liquids-handling facilities to serve growing equity and third-party production in its core areas of the Pinedale and Jonah fields in western Wyoming and the Uinta Basin in eastern Utah.

Gas Management completed its condensate and produced-water gathering and transportation facilities on Market Resources Pinedale Anticline leasehold in November 2005 in time to satisfy BLM conditions for expanded winter access.

Gas Management entered into an agreement with a third party producer to gather, compress and process gas in the Uinta Basin. Under terms of the fee-based agreement, the company constructed gas compression facilities and expanded its existing Red Wash gas plant to process an additional 70 MMcf per day of raw gas. The processed gas and liquids are redelivered to the producer. The new facilities were in service at the end of the third quarter 2005. Gas Management has formed a joint venture with the Ute Indian Tribe and another industry participant to build a gas gathering system for the Flat Rock area in southern Uinta Basin.

Energy Trading and Other
Energy Trading sells Market Resources equity gas and oil, provides risk-management services and operates a natural-gas storage facility, reported net income for 2006 of $9.6 million compared to $6.0 million in 2005 and $0.9 million in 2005. Service fee revenues from affiliates were $0.8 million higher in 2006 relative to 2005. Gross margins for gas and oil marketing (gross revenues less costs for gas and oil purchases, transportation and gas storage), increased to $16.0 million for 2006 versus $14.5 million a year ago, a 10% increase. The increase in gross margin was due primarily to a 5% increase in volumes and increased storage activity over the same period last year.

Consolidated Results Before Net Income

Net gain on asset sales
During 2006, Questar E&P sold certain proved reserves and undeveloped leasehold interests in western Colorado and recognized a pre-tax gain of $22.7 million. The gain is included in the Consolidated Statement of Income line item “Net gain on asset sales”. For income tax purposes, the Company structured the sale of the Colorado properties and the March 2006 acquisition of certain

Louisiana properties to qualify as a reverse like-kind exchange of property under Section 1031 of the Internal Revenue Code of 1986, as amended.

Income from unconsolidated affiliates
Gas Management has a 50% interest in Rendezvous that provides gas-gathering services for the Pinedale and Jonah producing areas of western Wyoming. Gas Management's share of Rendezvous earnings amounted to $7.0 million in 2006 compared to $7.2 million in 2005 and $5.0 million in 2004. Rendezvous gathering volumes increased 1% in 2006 compared to 2005 and 47% in 2005 compared to 2004.

Interest expense and loss on early extinguishment of debt
Interest expense rose in 2006 compared to 2005 due primarily to increased average debt levels and higher interest rates on short term debt outstanding in the early part of 2006. Market Resources recognized a $1.7 million pre-tax loss in 2006 on the early extinguishment of its 7% Notes due 2007.

Net mark-to-market loss on basis-only swaps
The Company uses basis-only swaps to protect cash flows and net income from widening natural gas-price basis differentials that may result from capacity constraints on regional gas pipelines. The Company recognized mark-to-market losses of $1.9 million on the NYMEX/Rockies basis-only swaps in 2006.

Investing Activities
Capital spending in 2006 amounted $752.7 million. The details of capital expenditures in 2006 and 2005 and a forecast for 2007 are shown in the table below:

	Year Ended December 31,		
	2007 Forecast	**2006**	2005
	(in millions)		
Drilling and other exploration	$ 31.4	**$ 13.6**	$ 51.7
Dry exploratory well expenses		**26.3**	3.1
Development drilling	476.8	**532.6**	355.1
Wexpro development drilling	62.6	**76.8**	53.7
Reserve acquisitions	1.0	**29.3**	3.5
Production	14.2	**22.7**	24.8
Gathering and processing	108.5	**80.4**	96.7
Storage	0.2	**1.1**	0.5
General	5.1	**5.6**	2.9
Capital expenditure accruals		**(35.7)**	(15.8)
Total	$699.8	**$752.7**	$576.2

In 2006 and 2005, Market Resources increased drilling activity at Pinedale and in the Midcontinent region. A water and condensate gathering system to serve the Pinedale Anticline was constructed in 2005. During 2006, Market Resources participated in 570 wells (196.3 net), resulting in 186.5 net successful gas and oil wells and 9.8 net dry or abandoned wells. The 2006 net drilling-success rate was 95%. There were 131 gross wells in progress at year end. Market Resources also increased investment in its midstream gathering and processing-services business to expand capacity in both western Wyoming and eastern Utah in response to growing equity and third-party production volumes.

Contractual Cash Obligations and Other Commitments
In the course of ordinary business activities, Market Resources enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2006:

	Payments Due by Year				
	Total	2007	2008-2009	2010-2011	After 2011
	(in millions)				
Long-term debt	$400.0			$150.0	$250.0
Transportation and storage contracts	61.1	$ 9.0	$15.8	14.1	22.2
Operating leases	7.0	3.5	2.6	0.9	
Total	$468.1	$12.5	$18.4	$165.0	$272.2

Critical Accounting Policies, Estimates and Assumptions
Market Resources significant accounting policies are described in Note 1 to the consolidated financial statements included in Item 8 of Part II of this 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 decisions 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, and economic assumptions relating to commodity prices, production costs, severance and other taxes, capital expenditures and remedial costs. The subjective decisions and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures. For 2006, revisions of reserve estimates, other than revisions related to Pinedale increased-density, resulted in a 23.8 Bcfe decrease in Questar E&P’s proved reserves and a 21.5 Bcfe increase in cost-of-service proved reserves, representing approximately one percent and three percent of reported proved reserves, respectively, as of December 31, 2006 . Revisions associated with Pinedale increased-density drilling added 170.4 Bcfe to Questar E&P’s estimated proved reserves at December 31, 2006, and 104.6 Bcfe of additional cost-of-service proved reserves. See Note 13 for more information on the Company’s estimated proved reserves.

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.

Questar E&P engages independent reservoir-engineering consultants 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.

Long-lived assets are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated on a field-by-field basis. Impairment is indicated when a triggering event occurs and the sum of estimated undiscounted future net cash flows of the evaluated asset is less than the asset's carrying value. The asset value is written down to estimated fair value, which is determined using discounted future net cash flows.

Accounting for Derivatives Contracts
The Company uses derivative contracts, typically fixed-price swaps, to hedge against a decline in the realized prices of its gas and oil 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 comprehensive income depending on the structure of the derivatives. The Company has structured virtually all energy-derivative instruments as cash-flow hedges as defined in SFAS 133 as amended. Changes in the fair value of cash-flow hedges are recorded on the balance sheet and in comprehensive income or loss 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.

Revenue Recognition
Revenues are recognized in the period that services are provided or products are delivered. Questar E&P 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 index prices and volumes supplied by field operators. A liability is recorded to the extent that Questar E&P has an imbalance in excess of its share of remaining reserves in an underlying property. Energy Trading presents revenues on a gross-revenue basis. Energy Trading 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.

Recent Accounting Developments
Refer to Note 1 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for a discussion of recent accounting developments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market Resources primary market risk exposures arise from commodity-price changes for natural gas, oil and NGL, and volatility in interest rates. Energy Trading has long-term contracts for pipeline capacity and is obligated for transportation services with no guarantee that it will be able to recover the full cost of these transportation commitments.

Commodity-Price Risk Management
Market Resources bears the risk associated with commodity-price changes and uses gas- and oil-price-derivative arrangements in the normal course of business to limit the risk of adverse price movements. However these same arrangements typically limit future gains from favorable price movements. Derivative contracts are used for a significant share of Questar E&P-owned gas and oil production, a portion of Energy Trading gas- and oil-marketing transactions and some of Gas Management's NGL.

Market Resources has established policies and procedures for managing commodity-price risks through the use of derivatives. Natural gas- and oil-price hedging support Market Resources rate of return and cash flow targets and protects earnings from downward movements in commodity prices. The volume of hedged production and the mix of derivative instruments are regularly evaluated and adjusted by management in response to changing market conditions and reviewed periodically by the Finance and Audit Committee of the Company's Board of Directors. Market Resources may hedge up to 100% of forecast production from proved reserves when prices meet earnings and cash flow objectives. Market Resources does not enter into derivative arrangements for speculative purposes and does not hedge undeveloped reserves or Questar E&P equity NGL.

Market Resources uses fixed-price swaps to manage natural gas, oil and NGL price risk. A fixed-price swap is a derivative instrument that exchanges or "swaps" the "floating" or daily price of a specified volume of natural gas, oil or NGL, over a specified period, for a fixed price for the specified volume over the same period. In the normal course of business, the Company sells its equity natural gas, oil and NGL production to third parties at first-of-the-month or daily "floating" prices related to indices reported in industry publications. To reduce exposure to highly volatile daily and monthly commodity prices, the Company uses a derivative instrument that exchanges or "swaps" the "floating" or daily price of the commodity for a fixed-price for the specified period (typically for periods of three months or longer). The Company enters into these transactions with banks and industry counterparties with investment-grade credit ratin gs. Swap agreements do not require the physical transfer of gas between the parties at settlement. Swap transactions are settled monthly, in cash, with one party paying the other for the net difference in prices, multiplied by the relevant volume, for the settlement period.

Generally derivative instruments are matched to equity gas and oil production, thus qualifying as cash flow hedges under the accounting provisions of SFAS 133 as amended and interpreted. Changes in the fair value of cash-flow hedges are recorded on the balance sheet and in other comprehensive income or loss until the underlying gas or oil is produced. Gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. The ineffective portion of cash flow hedges is immediately recognized in the determination of net income.

Market Resources also entered into natural gas basis-only swaps in 2006 to manage the risk of a widening of basis differentials in the Rocky Mountains. These contracts are marked-to-market with any change in the valuation recognized in the determination of net income.

Market Resources enters into commodity price derivative arrangements with several banks and energy-trading firms with a variety of credit requirements. Some contracts do not require collateral deposits, while others allow some amount of credit before Market Resources is required to deposit collateral for out-of-the-money contracts. The amount of credit available may vary depending on the credit rating assigned to Market Resources debt. In addition, to the counterparty arrangements, Market Resources has a $182 million long-term revolving-credit facility with banks with no borrowings outstanding at December 31, 2006.

A summary of Market Resources derivative positions for equity production as of December 31, 2006, is shown below. Currently fixed-price and basis-only swaps are with creditworthy counterparties. Fixed-price swaps allow Market Resources to realize a known price for a specific volume of production delivered into a regional sales point. The fixed-price swap price is then reduced by gathering costs and adjusted for product quality to determine the net-to-the-well price.

Time Periods	Rocky Mountains	Midcontinent	Total	Rocky Mountains	Midcontinent	Total
	Gas (in Bcf) Fixed-Price Swaps			Estimated Average price per Mcf, net to the well		
2007						
First half	23.1	15.4	38.5	$6.88	$7.81	$7.25
Second half	23.5	15.6	39.1	6.88	7.81	7.25
12 months	46.6	31.0	77.6	6.88	7.81	7.25
2008						
First half	16.9	12.2	29.1	$7.19	$7.98	$7.52
Second half	17.9	12.3	30.2	7.16	7.98	7.49
12 months	34.8	24.5	59.3	7.18	7.98	7.51
2009						
First half	13.4	8.7	22.1	$7.07	$7.55	$7.26
Second half	13.7	8.8	22.5	7.07	7.55	7.26
12 months	27.1	17.5	44.6	7.07	7.55	7.26
	Gas (in Bcf) Basis-Only Swaps			Estimated Average basis per Mcf vs. NYMEX		
2007						
First half	8.4		8.4	$1.92		$1.92
Second half	8.6		8.6	1.92		1.92
12 months	17.0		17.0	1.92		1.92

2008						
First half	13.6		13.6	$1.60		$1.60
Second half	13.7		13.7	1.60		1.60
12 months	27.3		27.3	1.60		1.60
2009						
First half	1.7		1.7	$0.95		$0.95
Second half	1.7		1.7	0.95		0.95
12 months	3.4		3.4	0.95		0.95
	Oil (in Mbbl) Fixed-Price Swaps			Average price per bbl, net to the well		
2007						
First half	525	199	724	$52.01	$57.91	$53.63
Second half	534	202	736	52.01	57.91	53.63
12 months	1,059	401	1,460	52.01	57.91	53.63
2008						
First half	109	73	182	$59.45	$65.45	$61.85
Second half	111	73	184	59.45	65.45	61.85
12 months	220	146	366	59.45	65.45	61.85

As of December 31, 2006, Market Resources held commodity-price hedging contracts covering about 204.2 million MMBtu of natural gas, 1.8 MMbbl of oil and 22.7 million gallons of NGL. A year earlier Market Resources hedging contracts covered 184.4 million MMBtu of natural gas, 2.9 MMbbl of oil and 10.1 million gallons of NGL. Market Resources has also entered into basis-only swaps on an additional 47.7 million Mcf of natural gas. There were no basis-only swaps a year earlier.

The following table summarizes changes in the fair value of derivative contracts from December 31, 2005, to December 31, 2006:

	Fixed-Price Swaps	Basis-Only Swaps	Total
		(in millions)	
Net fair value of gas- and oil-derivative contracts outstanding at December 31, 2005	($319.1)		($319.1)
Contracts realized or otherwise settled	167.1		167.1
Change in gas and oil prices on futures markets	236.6		236.6
Contracts added	121.0	($1.9)	119.1
Net fair value of gas- and oil-derivative contracts outstanding at December 31, 2006	**$205.6**	**($1.9)**	**$203.7**

A table of the net fair value of gas- and oil-derivative contracts as of December 31, 2006, is shown below. About 75% of the fair value of all contracts will settle in the next twelve months and the fair value of cash-flow hedges will be reclassified from other comprehensive income:

	Fixed-Price Swaps	Basis-Only Swaps	Total
		(in thousands)	
Contracts maturing by December 31, 2007	$153.9	$ 1.0	$154.9
Contracts maturing between December 31, 2007 and December 31, 2008	40.9	(3.0)	37.9
Contracts maturing between December 31, 2008 and December 31, 2009	10.8	0.1	10.9
Net fair value of gas- and oil-derivative contracts outstanding at December 31, 2006	**$205.6**	**($1.9)**	**$203.7**

The following table shows 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:

	At December 31,	
	2006	2005
	(in millions)	
Net fair value – asset (liability)	**$203.7**	($319.1)
Value if market prices of gas and oil and basis differentials decline by 10%	**334.6**	(166.9)
Value if market prices of gas and oil and basis differentials increase by 10%	**72.8**	(471.4)

Credit Risk

Market Resources requests credit support and, in some cases, prepayment from companies with unacceptable credit risks. Market Resources five largest customers are Sempra Energy Trading Corp., BP Energy Company, ONEOK Energy Services Company LP, Enterprise Products Operating and Nevada Power Company. Sales to these companies accounted for 27% of Market Resources revenues before elimination of intercompany transactions in 2006, and their accounts were current at December 31, 2006.

Interest Rate Risk

The fair value of fixed-rate debt is subject to change as interest rates fluctuate. The Company had $400.0 million of fixed-rate long-term debt with a fair value of $412.8 million at December 31, 2006. A year earlier the Company had $350.0 million of fixed-rate long-term debt with a fair value of $368.5 million. If interest rates would have declined 10%, fair value would increase to $427.2 million in 2006 and $373.4 million in 2005. The fair value calculations do not represent the cost to retire the debt securities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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 Shareholder
Questar Market Resources

We have audited the accompanying consolidated balance sheets of Questar Market Resources and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 Questar Market Resources and subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 2 to the financial statements, Questar Market Resources and subsidiaries adopted Statement of Financial Accounting Standards No. 123R, *Share Based Payment*, under the modified prospective phase-in method, effective January 1, 2006.

/s/ Ernst & Young LLP

Salt Lake City, UT
February 26, 2007

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
REVENUES			
From unaffiliated customers	**$1,659.4**	$1,668.7	$1,053.9
From affiliated companies	**176.4**	159.5	131.4
Total Revenues	**1,835.8**	1,828.2	1,185.3
OPERATING EXPENSES			
Cost of natural gas and other products sold	**652.6**	888.3	499.7
Operating and maintenance	**180.4**	158.6	113.8
General and administrative	**69.2**	54.6	49.6
Production and other taxes	**89.4**	102.2	73.2
Depreciation, depletion and amortization	**235.0**	173.8	142.7
Exploration	**34.4**	11.5	9.2
Abandonment and impairment	**7.6**	7.9	15.8
Wexpro Agreement-oil income sharing	**5.5**	6.1	4.7
Total Operating Expenses	**1,274.1**	1,403.0	908.7
Net gain on asset sales	**25.2**	0.9	0.3
OPERATING INCOME	**586.9**	426.1	276.9
Interest and other income	**5.8**	5.6	1.9
Income from unconsolidated affiliates	**7.5**	7.5	5.1
Net mark-to-market loss on basis-only swaps	**(1.9)**		
Loss on early extinguishment of debt	**(1.7)**		
Interest expense	**(33.9)**	(30.9)	(27.4)
INCOME BEFORE INCOME TAXES	**562.7**	408.3	256.5
Income taxes	**206.6**	150.1	91.1
NET INCOME	**$ 356.1**	$ 258.2	$ 165.4

See notes accompanying the consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 18.2**	$ 4.4
Notes receivable from Questar	**69.8**	89.1
Federal income taxes recoverable	**1.4**	14.1
Accounts receivable, net	**235.9**	258.9
Accounts receivable from affiliates	**21.8**	26.4
Derivative collateral deposits		5.1
Fair value of derivative contracts	**155.5**	2.0
Inventories, at lower of average cost or market		
Gas and oil storage	**27.7**	33.2
Materials and supplies	**28.7**	24.0
Prepaid expenses and other	**22.5**	23.4
Deferred income taxes – current		97.1
Total Current Assets	**581.5**	577.7
Property, Plant and Equipment – successful efforts method of accounting for gas and oil properties		
Questar E&P gas and oil properties		
Proved properties	**2,646.6**	2,047.9
Unproved properties, not being depleted	**42.7**	41.5
Support equipment and facilities	**18.5**	18.4
Wexpro cost-of-service gas and oil properties	**658.6**	561.5
Gas Management gathering processing	**404.2**	323.9
Energy Trading marketing and other	**37.9**	36.3
	3,808.5	3,029.5
Less accumulated depreciation, depletion and amortization		
Questar E&P gas and oil properties	**901.5**	731.1
Wexpro cost-of-service gas and oil properties	**305.4**	277.6
Gas Management gathering processing	**97.3**	82.2
Energy Trading marketing and other	**5.5**	4.6
	1,309.7	1,095.5
Net Property, Plant and Equipment	**2,498.8**	1,934.0
Investment in unconsolidated affiliates	**37.5**	30.7
Other Assets		
Goodwill	**60.9**	61.5
Contract receivable from Questar Gas	**4.2**	4.6
Fair value of derivative contracts	**49.0**	
Other noncurrent assets	**17.7**	12.8
Total Other Assets	**131.8**	78.9
Total Assets	**$3,249.6**	$2,621.3

LIABILITIES AND SHAREHOLDER'S EQUITY

	December 31, 2006	2005
	(in millions)	
Current Liabilities		
Notes payable to Questar	**$ 142.6**	$ 180.8
Accounts payable and accrued expenses		
Accounts and other payables	**295.3**	297.4
Accounts payable to affiliates	**17.3**	3.8
Production and other taxes	**53.4**	57.6
Interest	**8.8**	8.4
Total accounts payable and accrued expenses	**374.8**	367.2
Fair value of derivative contracts	**0.6**	222.1
Deferred income taxes – current	**41.7**	
Total Current Liabilities	**559.7**	770.1
Long-term debt	**399.2**	350.0
Deferred income taxes	**579.0**	408.4
Asset retirement obligations	**128.3**	74.3
Fair value of derivative contracts	**0.2**	99.0
Other long-term liabilities	**38.4**	45.7
Commitments and Contingencies – Note 8		
COMMON SHAREHOLDER'S EQUITY		
Common stock – par value $1 per share;		
25.0 shares authorized; 4.3 shares issued and outstanding	**4.3**	4.3
Additional paid-in capital	**122.0**	116.0
Retained earnings	**1,290.4**	951.6
Accumulated other comprehensive income (loss)	**128.1**	(198.1)
Total Common Shareholder's Equity	**1,544.8**	873.8
Total Liabilities and Common Shareholder's Equity	**$3,249.6**	$2,621.3

See notes accompanying the consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Comprehensive Income (Loss)
			(in millions)		
Balance at January 1, 2004	$ 4.3	$116.0	$ 562.6	($ 32.6)	
2004 net income			165.4		$165.4
Dividends paid			(17.3)		
Other comprehensive loss					
Change in unrealized loss on derivatives				(15.2)	(15.2)
Income taxes				5.7	5.7
Total comprehensive income					$155.9
Balance at December 31, 2004	4.3	116.0	710.7	(42.1)	
2005 net income			258.2		$258.2
Dividends paid			(17.3)		
Other comprehensive loss					
Change in unrealized loss on derivatives				(251.5)	(251.5)
Income taxes				95.5	95.5
Total comprehensive income					$102.2
Balance at December 31, 2005	4.3	116.0	951.6	(198.1)	
2006 net income			356.1		$356.1
Dividends paid			(17.3)		
Share-based compensation		6.0			
Other comprehensive income					
Change in unrealized gain on derivatives				524.9	524.9
Income taxes				(198.7)	(198.7)
Total comprehensive income					**$682.3**
Balance at December 31, 2006	**$ 4.3**	**$122.0**	**$1,290.4**	**$128.1**	

See notes accompanying the consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
OPERATING ACTIVITIES			
Net income	**$356.1**	$258.2	$165.4
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation, depletion and amortization	**236.8**	174.9	147.1
Deferred income taxes	**110.7**	93.2	68.6
Abandonment and impairment	**7.6**	7.9	15.8
Share-based compensation	**6.0**		
Dry exploration well expenses	**26.3**	3.1	4.0
Net gain from asset sales	**(25.2)**	(0.9)	(0.3)
Income from unconsolidated affiliates	**(7.5)**	(7.5)	(5.1)
Distribution from unconsolidated affiliates	**7.1**	10.0	8.3
Net mark-to-market loss on basis-only swaps	**1.9**		
Loss on early extinguishment of debt	**1.7**		
Changes in operating assets and liabilities:			
Accounts receivable	**32.7**	(95.3)	(39.7)
Inventories	**0.7**	(26.0)	(10.3)
Prepaid expenses and other	**0.9**	(6.7)	(7.2)
Accounts payable and accrued expenses	**(28.0)**	121.2	63.4
Federal income taxes	**12.7**	(18.7)	2.3
Other assets	**(4.0)**	2.3	(6.8)
Other liabilities	**(8.1)**	4.7	11.3
NET CASH PROVIDED FROM OPERATING ACTIVITIES	**728.4**	520.4	416.8
INVESTING ACTIVITIES			
Capital expenditures			
Property, plant and equipment	**(746.4)**	(576.2)	(335.8)
Other investments	**(6.3)**		(1.0)
Total capital expenditures	**(752.7)**	(576.2)	(336.8)
Proceeds from disposition of assets	**29.0**	1.9	2.1
NET CASH USED IN INVESTING ACTIVITIES	**(723.7)**	(574.3)	(334.7)
FINANCING ACTIVITIES			
Checks in excess of cash balances		(4.3)	4.3
Change in notes receivable from Questar	**19.3**	(39.7)	(42.5)
Change in notes payable to Questar	**(38.2)**	119.6	24.7
Long-term debt issued, net of issue costs	**247.0**	200.0	
Long-term debt repaid	**(200.0)**	(200.0)	(55.0)
Early extinguishment of debt costs	**(1.7)**		

Dividends paid	**(17.3)**	(17.3)	(17.3)
NET CASH (USED IN) PROVIDED FROM FINANCING ACTIVITIES	**9.1**	58.3	(85.8)
Change in cash and cash equivalents	**13.8**	4.4	(3.7)
Beginning cash and cash equivalents	**4.4**		3.7
Ending cash and cash equivalents	**$ 18.2**	$ 4.4	$

See notes accompanying the consolidated financial statements

Note 1 – Summary of Significant Accounting Policies

Nature of Business
Questar Market Resources, Inc. (Market Resources or the Company) is a natural gas-focused energy company, a wholly owned subsidiary of Questar Corporation (Questar) and Questar's primary growth driver. Market Resources is a subholding company with four principal subsidiaries:

- Questar Exploration and Production Company (Questar E&P) acquires, explores for, develops and produces natural gas, oil, and NGL;
- Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for gas utility affiliate, Questar Gas;
- Questar Gas Management Company (Gas Management) provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and
- Questar Energy Trading Company (Energy Trading) markets equity and third-party gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Principles of Consolidation
The consolidated financial statements contain the accounts of Market Resources 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.

Investments in Unconsolidated Affiliates
Market Resources 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 would be included in the determination of net income.

The principal affiliates and Market Resources' ownership percentage as of December 31, 2006, were Rendezvous Gas Services, LLC, a limited liability corporation (50%), Uintah Basin Field Services, LLC, a limited liability corporation (38%) and Canyon Creek Compression Company, a general partnership (15%). These entities are engaged in gathering and compressing natural gas.

Use of Estimates
The preparation of consolidated financial statements and notes in conformity with GAAP requires management to formulate estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Revenue Recognition
Market Resources 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 production of 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. Market Resources imbalance obligations at December 31, 2006 and 2005, were $2.7 million and $2.5 million, respectively.

Energy Trading 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. Market Resources is primarily engaged in gas and oil exploration and production and midstream field services. Energy Trading markets equity natural gas, oil and NGL and third-party volumes. Energy Trading uses derivatives to secure a known price for a specific volume over a specific time period. Energy Trading 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. Energy Trading has not engaged in buy/sell arrangements, as described in

EITF 04-13 “Accounting for Purchases and Sales of Inventory with the Same Counterparty,” and therefore has not provided the related disclosure.

Wexpro Agreement – Oil Income Sharing
Oil income sharing represents payments made to Questar Gas for its share of the income from oil and NGL products associated with cost-of-service properties pursuant to the Wexpro Agreement. See Note 11 for more information on the Wexpro Agreement.

Regulation of Underground Storage
Market Resources through Clear Creek Storage Company, LLC, operates a 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.

Derivative Collateral Deposits
Derivative collateral deposits represent cash collateral deposited with counterparties under the terms of derivative agreements. Some counterparties may require the Company to deposit cash collateral when the derivative transactions under these agreements are out-of-the-money by an amount that exceeds counterparty credit limits. The deposits are restricted until either the derivative transaction returns to in-the-money status or the open position is settled.

Notes Receivable from Questar
Notes receivable from Questar represent interest bearing demand notes for cash loaned to Questar until needed in the Company’s operations. The funds are centrally managed by Questar and earn an interest rate that is identical to the interest rate paid by the Company for borrowings from Questar.

Property, Plant and Equipment
Property, plant and equipment balances are stated at historical cost. Maintenance and repair costs are expensed as incurred.

Gas and oil properties
Questar E&P 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 and depreciated on a field basis using the unit-of-production method and the estimated proved developed gas and oil reserves. Costs of 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. 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 exploratory well costs
The Company capitalizes exploratory well costs until it determines whether the 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.

Cost-of-service gas and oil operations
The successful efforts method of accounting is used for “cost-of-service” gas and oil properties owned by Questar Gas and managed and developed by Wexpro. Cost-of-service gas and oil properties are properties for which the operations and return on investment are subject to the Wexpro Agreement (see Note 11). In accordance with the agreement, production from the gas properties operated by Wexpro is delivered to Questar Gas at Wexpro’s cost of providing this service. That cost includes a return on Wexpro’s investment. Oil produced from the cost-of-service properties is sold at market prices. Proceeds are credited pursuant to the terms of the agreement, allowing Questar Gas to share in the proceeds for the purpose of reducing natural gas rates.

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. The following rates per Mcfe represent the volume-weighted average depreciation, depletion and amortization rates of the Company’s capitalized costs for the periods:

	2006	2005	2004
Gas and oil properties, per Mcfe	**$1.43**	$1.18	$1.04
Cost-of-service gas and oil properties, per Mcfe	**1.04**	0.83	0.82

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.

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 an impairment of gas and oil reserves caused by mechanical problems, a faster-than-expected decline of reserves, lease-ownership issues, an other-than-temporary decline in gas and oil prices and changes in the utilization of pipeline 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.

Goodwill and Other Intangible Assets
Goodwill represents the excess of the amount paid by Questar E&P 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.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)
The Company capitalizes interest costs when applicable. The Wexpro Agreement requires capitalization of AFUDC on cost-of-service construction projects. The FERC requires the capitalization of AFUDC during the construction period of rate-regulated plant and equipment, such as our underground-gas storage facility. AFUDC amounted to $0.9 million in 2006, $0.4 million in 2005 and $0.2 million in 2004 and increased interest and other income in the Consolidated Statements of Income.

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 other comprehensive income 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.

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 net income.

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. Market Resources 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 cost of sales in the month of settlement.

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. Market Resources requests credit support and, in some cases, fungible collateral from companies with unacceptable credit risks. The C ompany has a master-netting agreement with some customers that allows the offsetting of receivables and payables in a default situation.

Bad debt expense amounted to $1.4 million in 2006, $0.1 million in 2005 and zero in 2004. The allowance for bad debt expenses was $4.3 million and $2.9 million at December 31, 2006 and 2005, respectively.

Income Taxes
Questar and its subsidiaries file a consolidated federal income tax return. Market Resources accounts for income tax expense on a separate-return basis and records tax benefits as they are generated. The Company receives payments from Questar for such tax benefits as they are utilized on the consolidated income tax return. Deferred income taxes have been provided for temporary differences caused by differences between the book and tax-carrying amounts of assets and liabilities. These differences create taxable or tax deductible amounts for future periods. Interest earned on refunds is recorded in interest and other income. Interest expense charged on tax deficiencies is recorded in interest expense.

Share-Based Compensation
Questar issues stock options and restricted shares to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). Prior to January 1, 2006, the Company accounted for share-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion (APBO) 25 “Accounting for Stock Issued to Employees” and related interpretations. No compensation cost was recorded for stock options issued because the exercise price equaled the market price on the date of grant. The granting of restricted shares resulted in recognition of compensation cost measured at the grant-date market price.

The Company implemented Statement of Financial Accounting Standards 123R “Share Based Payment,” (SFAS 123R) effective January 1, 2006, and chose the modified prospective phase-in method. The modified prospective phase-in method requires recognition of compensation costs for all share-based payments granted, modified or settled after January 1, 2006, as well as for any awards that were granted prior to the implementation date for which the required service has not yet been performed. Market Resources uses an accelerated method in recognizing share-based compensation costs with graded-vesting periods.

Comprehensive Income
Comprehensive income is the sum of net income as reported in the Consolidated Statement of Income and other comprehensive income transactions reported in the Consolidated Statement of Common Shareholder’s Equity. Other comprehensive income or loss is the result of changes in the market value of gas and oil cash-flow derivatives. These transactions are not the culmination of the earnings process, but result from periodically adjusting historical balances to fair value. Income or loss is realized when the underlying energy product is sold.

Business Segments
Market Resources has four major segments: Questar E&P, Wexpro, Gas Management and Energy Trading. 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. Certain intersegment sales include intercompany profit.

Recent Accounting Developments
In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation 48 “Accounting for Uncertainty in Income Taxes” (FIN 48). The interpretation applies to all tax positions related to income taxes subject to FASB Statement 109 “Accounting for Income Taxes.” FIN 48 clarifies 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. FIN 48 is effective beginning January 1, 2007. The Company does not expect the provisions of FIN 48 will have a significant impact on its financial statements.

In September 2006, the FASB issued SFAS 157 “Fair Value Measures”. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007. The Company is continuing to assess the impact of SFAS 157.

In December 2006, the FASB issued an exposure draft titled “Disclosures about Derivative Instruments and Hedging Activities.” The proposed statement would amend and expand the disclosure requirements in SFAS 133 “Accounting for Derivative Instruments and Hedging Activities”, and other related accounting pronouncements. The proposed expanded disclosure is intended to provide enhanced understanding of (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations; and (iii) how derivative instruments affect an entity's financial position, results of operations, and cash flows. The proposed effective date would be for fiscal years and interim periods ending after December 15, 2007. The Company has not evaluated the potential effect of the proposed disclosures.

In February 2007, the FASB issued SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities." SFAS 159 permits the measurement of certain financial instruments at fair value. Entities may choose to measure eligible items at fair value at specified election dates, reporting unrealized gains and losses on such items at each subsequent reporting period. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The Company has not evaluated the potential impact of the fair value option.

Reclassifications
Certain reclassifications were made to prior-year consolidated financial statements to conform with the 2006 presentation. Amounts are presented in millions of dollars, the Consolidated Statement of Income includes a line item for net gain on asset sales and dry exploration well expenses is a line item in operating activities on the Consolidated Statement of Cash Flows requiring a reciprocal adjustment in capital expenditures.

Note 2 – Share-Based Compensation

Prior to January 1, 2006, Questar and the Company accounted for share-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion (APBO) 25 "Accounting for Stock Issued to Employees" and related interpretations. No compensation cost was recorded for stock options because the exercise price equaled the market price on the date of grant. The granting of restricted shares results in recognition of compensation cost. Restricted shares are valued at the grant-date market price and amortized to expense over the vesting period.

Questar and the Company implemented SFAS 123R "Share Based Payment," effective January 1, 2006, and chose the modified prospective phase-in method of accounting by SFAS 123R. The modified prospective phase-in method requires recognition of compensation costs for all share-based payments granted, modified or settled after January 1, 2006, as well as for any awards that were granted prior to the implementation date for which the required service has not yet been performed. As a result of adopting SFAS 123R, the Company's income before income taxes and net income for the year ended December 31, 2006, were approximately $0.7 million and $0.4 million lower, respectively, than if the Company had continued to account for share-based compensation under APBO 25. The pro forma share-based compensation expense impact for the year of 2005 was approximately $0.8 million. Share-based compensation associated with unvested restricted shares amounted to $5.3 million for the year ended Dec ember 31, 2006.

Transactions involving stock options granted to employees of Market Resources under the LTSIP are summarized below:

	Outstanding Options	Price Range	Weighted Average Price
Balance at January 1, 2006	901,319	$15.00 – $77.14	$30.17
Exercised	(182,248)	15.00 – 35.10	23.14
Balance at December 31, 2006	**719,071**	**$15.00 – $77.14**	**$31.95**

The number of unvested stock options held by Market Resources employees decreased by 67,875 shares in 2006.

Options Outstanding				Options Exercisable		Unvested Options	
Range of exercise prices	Number outstanding at Dec. 31, 2006	Weighted-average remaining term in years	Weighted-average exercise price	Number exercisable at Dec. 31, 2006	Weighted-average exercise price	Number unvested at Dec. 31, 2006	Weighted average exercise price
$15.00 - $17.00	69,314	3.0	$15.92	69,314	$15.92		
19.13 - 23.95	234,312	4.7	23.02	234,312	23.02		
27.11 - 29.71	301,506	5.7	27.44	301,506	27.44		
$35.10 - $77.14	113,939	4.5	72.00	7,689	35.10	106,250	$74.67
	719,071	4.9	$31.95	612,821	$24.52	106,250	$74.67

Most restricted share grants vest in equal installments over a three to five year period from the grant date. Several grants vest in a single installment after a specified period. The weighted average vesting period of unvested restricted shares at December 31, 2006, was 16 months. Transactions involving restricted shares in the LTSIP in 2006 are summarized below:

	Shares	Price Range	Weighted Average Price
Balance at January 1, 2006	177,241	$27.11 - $86.03	$41.28
Granted	115,790	70.40 - 89.54	74.19
Distributed	(60,663)	27.11 - 86.03	35.70
Forfeited	(2,495)	28.72 - 75.99	62.28
Balance at December 31, 2006	**229,873**	**$27.11 - $89.54**	**$59.10**

Note 3 – Asset Retirement Obligations (ARO)

Market Resources recognizes ARO in accordance with SFAS 143 "Accounting for Asset Retirement Obligations." SFAS 143 addresses the financial accounting and reporting of the fair value of legal obligations associated with the retirement of tangible long-lived assets. The Company's ARO applies primarily to plugging and abandonment costs associated with gas and oil wells and certain other properties. The fair value of abandonment costs are estimated and depreciated over the life of the related assets. Revisions to estimates of the ARO result from changes in expected cash flows. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Changes in asset retirement obligations were as follows:

	2006	2005
	(in millions)	
ARO liability at January 1,	**$ 74.3**	$66.4
Accretion	**6.9**	4.2
Liabilities incurred	**11.1**	5.0
Revisions	**38.2**	
Liabilities settled	**(2.2)**	(1.3)
ARO liability at December 31,	**$128.3**	$74.3

Wexpro activities are governed by a long-standing agreement with the states of Utah and Wyoming (the Wexpro Agreement). The accounting treatment of reclamation activities associated with ARO for properties administered under the Wexpro Agreement is spelled out in a guideline letter between Wexpro and the Utah Division of Public Utilities and the staff of the Public Service

Commission of Wyoming (PSCW). Accordingly, Wexpro collects from Questar Gas and deposits in trust funds related to estimated ARO costs. The funds are used to satisfy retirement obligations as the properties are abandoned. At December 31, 2006, approximately $5.8 million was held in this trust invested primarily in a short-term bond index fund.

Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs in 2006, 2005 and 2004 are as follows and exclude amounts that were capitalized and subsequently expensed in the period:

	2006	2005	2004
		(in millions)	
Balance at January 1,	**$ 16.5**	$14.6	$ 1.0
Additions to capitalized exploratory well costs pending the determination of proved reserves		9.8	14.1
Reclassifications to property, plant and equipment after the determination of proved reserves	**(5.0)**	(5.7)	(0.5)
Capitalized exploratory well costs charged to expense	**(11.5)**	(2.2)	
Balance at December 31,	**$**	$16.5	$14.6

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and any projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

		December 31,	
	2006	2005	2004
		(in millions)	
Capitalized exploratory well costs that have been capitalized one year or less	**$**	$ 9.8	$14.1
Capitalized exploratory well costs that have been capitalized longer than one year		6.7	0.5
Balance at end of period	**$**	$16.5	$14.6

Note 5 – Debt

Questar makes loans to Market Resources under a short-term borrowing arrangement. Short-term notes payable to Questar are subordinated to obligations under the revolving credit agreement. Short-term notes payable to Questar amounted to $142.6 million with an interest rate of 5.44% and $180.8 million with an interest rate of 4.42% at December 31, 2006 and 2005, respectively.

All long-term notes and the term loan are unsecured obligations and rank equally with all other unsecured liabilities. Market Resources revolving credit agreement had no borrowings outstanding at December 31, 2006 or 2005, but was fully drawn during part of 2005. This credit agreement carries an annual commitment fee of 0.115% of the unused balance. At December 31, 2006, Market Resources could pay dividends of $634.0 million without violating the terms of their debt covenants.

On May 11, 2006, Market Resources sold $250 million principal amount of 6.05% Notes due 2016. Net proceeds of $247 million were used for general corporate purposes including the June 14, 2006, early extinguishment of $200 million of 7% Notes due 2007. Market Resources recorded a $1.7 million charge related to the early extinguishment. The details of long-term debt are listed in the table below:

	December 31, 2006	2005
	(in millions)	
7.0% notes due 2007		$200.0
7.5% notes due 2011	**$150.0**	150.0
6.05% notes due 2016	**250.0**	
$182 million revolving credit agreement due 2011		
Total long-term debt outstanding	**400.0**	
Less unamortized-debt discount	**(0.8)**	
Total long-term debt outstanding	**$399.2**	$350.0

Repayment of the Company's 7.5% notes in 2011 is the only long-term debt maturity in the five years following December 31, 2006.

Cash paid for interest was $31.9 million in 2006, $30.4 million in 2005 and $26.9 million in 2004.

Note 6 – Financial Instruments and Risk Management

The carrying value and estimated fair values of Market Resources financial instruments were as follows:

	December 31, 2006		December 31, 2005	
	Carrying Value	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
		(in millions)		
Financial assets				
Cash and cash equivalents	**$ 18.2**	**$ 18.2**	$ 4.4	$ 4.4
Notes receivable from Questar	**69.8**	**69.8**	89.1	89.1
Fair value of derivative contracts	**204.5**	**204.5**	2.0	2.0
Financial liabilities				
Notes payable to Questar	**142.6**	**142.6**	180.8	180.8
Long-term debt	**400.0**	**412.8**	350.0	368.5
Fair value of derivative contracts	**0.8**	**0.8**	321.1	321.1

The Company used the following methods and assumptions in estimating fair values.

Cash and cash equivalents and short-term debt – the carrying amount approximates fair value.

Long-term debt – the carrying amount of variable-rate debt approximates fair value. The fair value of fixed-rate debt is based on the discounted present value of cash flows using the Company's current borrowing rates.

Derivative instruments – fair value of the contracts is based on market prices as posted on the NYMEX from the last trading day of the year. Gas derivatives are structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Market Resources held gas-price-derivative instruments covering the price exposure for about 204.2 million MMBtu of natural gas, 1.8 MMbbl of oil and 22.7 MMgal of NGL as of December 31, 2006. Gas Management, a subsidiary of Market Resources, uses forward-sales contracts to secure the price received for NGL processed from its plants. About 75% of the fair value of all contracts will settle and be reclassified from other comprehensive income in the next 12 months. A year earlier Market Resources derivatives covered the price exposure for about 184.4 million MMBtu of natural gas, 2.9 MMbbl of oil and 10.1 MMgal of NGL.

At December 31, 2006, the Company reported assets, net of liabilities, of $196.1 million related to derivatives. The offset to the derivative assets, net of income taxes, was a $128.1 million unrealized gain on derivatives recorded in other comprehensive income in the shareholder's equity section of the consolidated balance sheet. The ineffective portion of derivative transactions recognized in earnings was not significant. The fair-value calculation of gas- and oil-price derivatives does not consider changes in the fair value of the corresponding scheduled equity physical transactions, (i.e., the correlation between index price and the price realized for the physical delivery of gas or oil).

Note 7 – Income Taxes

Details of Market Resources income tax expense and deferred income taxes are provided in the following tables. The components of income taxes were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Federal			
Current	**$ 89.3**	$ 65.5	$24.1
Deferred	**98.5**	71.8	59.5
State			
Current	**6.6**	5.4	(1.6)
Deferred	**12.2**	7.4	9.1
	$206.6	$150.1	$91.1

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,		
	2006	2005	2004
Federal income tax statutory rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.2**	2.0	1.9
Domestic production benefit	**(0.4)**	(0.3)	
Percentage depletion	**(0.1)**	(0.1)	(0.4)
Other		0.2	(1.0)
Effective income tax rate	**36.7%**	36.8%	35.5%

Significant components of the Company's deferred income taxes were as follows:

	December 31,	
	2006	2005
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$565.0**	$448.4
Energy price derivatives	**18.9**	
Total deferred tax liabilities	**583.9**	448.4

Deferred tax assets		
Energy price derivatives		37.5
Employee benefits and compensation costs	**4.9**	2.5
Total deferred tax assets	**4.9**	40.0
Net deferred income taxes	**$579.0**	$408.4

Deferred income taxes – current asset (liability)		
Energy price derivatives	**($58.3)**	$83.3
Other	**16.6**	13.8
Deferred income taxes – current	**($41.7)**	$97.1

Cash paid for income taxes was $81.1 million in 2006, $73.8 million in 2005 and $22.6 million in 2004.

Note 8 – Commitments and Contingencies

Market Resources 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 Market Resources financial position. An accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. 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.

Subsidiaries of Market Resources have contracted for firm-transportation services with various third-party pipelines through 2018. Market conditions and competition may prevent full recovery of the cost. Annual payments and the years covered are as follows:

	(in millions)
2007	$ 9.0
2008	8.3
2009	7.5
2010	7.2
2011	6.9
2012 through 2018	$22.2

Market Resources rents office space throughout its scope of operations from third-party lessors and leases space in an office building located in Salt Lake City, Utah from an affiliated company that expires October 31, 2007. The minimum future payments under the terms of long-term operating leases for the Company’s primary office locations for the six years following December 31, 2006, are as follows:

	(in millions)
2007	$2.6
2008	1.9
2009	1.6
2010	1.3
2011	1.3
2012	0.9

Total rental expense amounted to $2.5 million in 2006, $2.2 million in 2005 and $2.2 million in 2004.

Note 9 – Employee Benefits

Pension Plan

Certain Market Resources employees are covered by Questar's defined benefit pension plan. Benefits are generally based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly pay period interval during the 10 years preceding retirement. Questar is subject to and complies with minimum required and maximum allowed annual contribution levels mandated by the Employee Retirement Income Security Act and by the Internal Revenue Code. Subject to the above limitations, Questar intends to fund the qualified pension plan approximately equal to the yearly expense. Questar also has a nonqualified pension plan that covers certain management employees in addition to the qualified pension plan. The nonqualified pension plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee above the benefit limit defined by the Internal Revenue Service for the qualified pla n. The nonqualified pension plan is unfunded. Claims are paid from the Company's general funds. Qualified pension plan assets consist principally of equity securities and corporate and U.S. government debt obligations. A third-party consultant calculates the pension plan projected benefit obligation. Pension expense was $4.9 million in 2006, $3.3 million in 2005 and $2.8 million in 2004.

Market Resources portion of plan assets and benefit obligations can not be determined because the plan assets are not segregated or restricted to meet the Company's pension obligations. If the Company were to withdraw from the pension plan, the pension obligation for the Company's employees would be retained by the pension plan. At December 31, 2006 and 2005, Questar's projected benefit obligation exceeded the fair value of plan assets.

Postretirement Benefits Other Than Pensions

Eligible Market Resources employees participate in Questar's postretirement benefits other than pensions 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, based on an employee's years of service, and generally limits payments to 170% of the 1992 contribution. Plan assets consist of equity securities and corporate and U.S. government debt obligations. A third party consultant calculates the projected benefit obligation. The cost of postretirement benefits other than pensions was $1.3 million in 2006, $1.2 million in 2005 and $1.4 million in 2004.

The Company's portion of plan assets and benefit obligations related to post-retirement medical and life insurance benefits can not be determined because the plan assets are not segregated or restricted to meet the Company's obligations. At December 31, 2006 and 2005, Questar's accumulated benefit obligation exceeded the fair value of plan assets.

Employee Investment Plan

Market Resources subsidiaries participate in Questar's Employee Investment Plan (EIP).The EIP allows eligible employees to purchase shares of Questar 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 80% of employees' pre-tax purchases up to a maximum of 6% of their qualifying earnings. In addition, the Company contributes $200 annually to the EIP for each eligible employee. Beginning in 2005, the EIP trustee purchased Questar shares on the open market as cash contributions are received. The Company's expense equaled its matching contribution of $2.4 million, $2.1 million and $1.8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Note 10 – Related Party Transactions

Market Resources receives a portion of its revenues from services provided to affiliate, Questar Gas. The Company received $176.4 million in 2006, $159.5 million in 2005 and $131.4 million in 2004 for operating cost-of-service gas properties, gathering gas and supplying a portion of gas for resale, among other services provided to Questar Gas. Operation of cost-of-service gas properties is described in Wexpro Agreement (Note 11).

Market Resources pays Questar for certain administrative services. These payments were $11.5 million in 2006, $13.0 million in 2005 and $10.1 million in 2004 and were included in operating expenses. Questar allocates the costs based on each affiliate's proportional share of revenues, net of gas costs; property, plant and equipment; and payroll. Management believes that the allocation method is reasonable.

Market Resources contracted for transportation and storage services with affiliate Questar Pipeline and paid $3.7 million in 2006, $2.8 million in 2005 and $2.2 million in 2004 for these services. Prior to mid 2005, Energy Trading marketed liquids extracted from Questar Pipeline's transportation lines paying $3.6 million in 2005 and $5.9 million in 2004. Questar InfoComm, an affiliated company that previously provided some information technology and communication services to Market Resources was paid $0.2 million in 2005 and $0.8 million in 2004.

Market Resources has a lease with Questar for space in an office building located in Salt Lake City, Utah, that expires October 31, 2007. The building is owned by a third party. The third party has a lease arrangement with Questar, which in turn sublets office space to affiliated companies. Market Resources paid $0.7 million in 2006 and $0.8 million per year in 2005 and 2004.

The Company received interest income from affiliated companies of $3.4 million in 2006, $0.8 million in 2005 and $0.2 million in 2004. Market Resources incurred interest expense to affiliated companies of $4.4 million in 2006, $3.8 million in 2005 and $0.9 million in 2004.

Note 11 – Wexpro Agreement

Wexpro's operations are subject to the terms of the Wexpro Agreement. The agreement was effective August 1, 1981, and sets forth the rights of Questar Gas's utility operations to receive certain benefits from Wexpro's operations. The agreement was approved by the PSCU and PSCW in 1981 and affirmed by the Supreme Court of Utah in 1983. Major provisions of the agreement are as follows.

a. Wexpro conducts gas-development drilling on a finite group of productive gas properties, as defined in the agreement, and bears any costs of dry holes. Natural gas produced from successful drilling on these properties is delivered to Questar Gas. Wexpro is reimbursed for the costs of producing the natural gas plus a return on its investment in successful wells. The after-tax return allowed Wexpro is adjusted annually and is approximately 20.9%.

b. Wexpro operates natural gas properties for Questar Gas. Wexpro is reimbursed for its costs of operating these properties, including a rate of return on any investment it makes. This after-tax rate of return is adjusted annually and is approximately 12.9%.

c. Production from a finite group of oil-producing properties is sold at market prices with the revenues used to recover operating expenses and to give Wexpro a return on its investment. The after-tax rate of return is adjusted annually and is approximately 12.9%. Any net income remaining after recovery of expenses and Wexpro's return on investment is divided between Wexpro and Questar Gas, with Wexpro retaining 46%.

d. Wexpro conducts developmental-oil drilling on productive oil properties and bears any costs of dry holes. Oil discovered from these properties is sold at market prices with the revenues used to recover operating expenses and to give Wexpro a return on its investment in successful wells. The after-tax rate of return is adjusted annually and is approximately 17.9%. Any net income remaining after recovery of expenses and Wexpro's return on investment is divided between Wexpro and Questar Gas with Wexpro retaining 46%.

e. Amounts received by Questar Gas from the sharing of Wexpro's oil income are used to reduce natural-gas costs to utility customers.

Wexpro's investment base, net of depreciation and deferred income taxes, and the yearly average rate of return for 2006 and the previous two years are shown in the table below:

	2006	2005	2004
Wexpro's net investment base (in millions)	**$260.6**	$206.3	$182.8
Average annual rate of return (after tax)	**19.9%**	20.4%	19.7%

Note 12 – Operations by Line of Business

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, 2006:

	Market Resources Consolidated	Interco. Transactions	Questar E&P	Wexpro	Gas Management	Energy Trading
			(in millions)			
2006						
Revenues						
From unaffiliated customers	**$1,659.4**		**$ 815.7**	**$ 19.7**	**$168.0**	**$ 656.0**
From affiliated companies	**176.4**	**($687.8)**		**150.5**	**15.9**	**697.8**
Total Revenues	**1,835.8**	**(687.8)**	**815.7**	**170.2**	**183.9**	**1,353.8**
Operating expenses						
Cost of natural gas and other products sold	**652.6**	**(686.0)**	**2.8**			**1,335.8**
Operating and maintenance	**180.4**	**(1.1)**	**73.6**	**14.7**	**92.4**	**0.8**
General and administrative	**69.2**	**(0.7)**	**42.4**	**11.3**	**12.2**	**4.0**
Production and other taxes	**89.4**		**58.3**	**30.3**	**0.6**	**0.2**
Depreciation, depletion and amortization	**235.0**		**185.7**	**33.1**	**15.3**	**0.9**
Other operating expenses	**47.5**		**42.0**	**5.5**		
Total operating expenses	**1,274.1**	**(687.8)**	**404.8**	**94.9**	**120.5**	**1,341.7**
Net gain (loss) on asset sales	**25.2**		**24.3**	**(0.1)**	**1.0**	
Operating income	**586.9**		**435.2**	**75.2**	**64.4**	**12.1**
Interest and other income (expense)	**2.2**	**(27.0)**	**(3.7)**	**1.3**		**31.6**
Income from unconsolidated affiliates	**7.5**		**0.4**		**7.1**	
Interest expense	**(33.9)**	**27.0**	**(27.1)**	**(0.5)**	**(4.7)**	**(28.6)**
Income tax expense	**(206.6)**		**(150.9)**	**(26.0)**	**(24.2)**	**(5.5)**
Net income	**$ 356.1**		**$ 253.9**	**$ 50.0**	**$ 42.6**	**$ 9.6**
Identifiable assets	**$3,249.6**		**$2,169.9**	**$397.1**	**$377.1**	**$305.5**
Investment in unconsolidated affiliates	**37.5**				**37.3**	**0.2**
Capital expenditures	**752.7**		**586.3**	**82.7**	**82.2**	**1.5**
Goodwill	**60.9**		**60.9**			
***200*5						
Revenues						
From unaffiliated customers	$1,668.7		$ 620.6	$ 21.7	$ 141.5	$ 884.9
From affiliated companies	159.5	($618.9)		132.3	13.7	632.4
Total Revenues	1,828.2	(618.9)	620.6	154.0	155.2	1,517.3
Operating expenses						
Cost of natural gas and other products sold	888.3	(617.6)	4.2			1,501.7
Operating and maintenance	158.6	(0.6)	61.8	11.2	85.2	1.0
General and administrative	54.6	(0.7)	33.9	10.0	7.5	3.9
Production and other taxes	102.2		68.7	32.6	0.7	0.2
Depreciation, depletion and amortization	173.8		134.7	26.9	11.3	0.9
Other operating expenses	25.5		18.8	6.7		
Total operating expenses	1,403.0	(618.9)	322.1	87.4	104.7	1,507.7
Net gain (loss) on asset sales	0.9		1.1	(0.2)		
Operating income	426.1		299.6	66.4	50.5	9.6
Interest and other income	5.6	(26.2)	0.6	0.9	0.3	30.0
Income from unconsolidated affiliates	7.5		0.3		7.2	

Interest expense	(30.9)	26.2	(23.7)	(0.1)	(3.1)	(30.2)
Income tax expense	(150.1)		(104.0)	(23.5)	(19.2)	(3.4)
Net income	$ 258.2		$ 172.8	$ 43.7	$ 35.7	$ 6.0
Identifiable assets	$2,621.3		$1,656.7	$ 331.2	$ 301.8	$ 331.6
Investment in unconsolidated affiliates	30.7		0.1		30.3	0.3
Capital expenditures	576.2		424.2	57.8	93.3	0.9
Goodwill	61.5		61.5			
2004						
Revenues						
From unaffiliated customers	$1,053.9		$ 448.7	$ 17.4	$ 87.3	$ 500.5
From affiliated companies	131.4	($422.2)	0.1	115.6	11.6	426.3
Total Revenues	1,185.3	(422.2)	448.8	133.0	98.9	926.8
Operating expenses						
Cost of natural gas and other products sold	499.7	(422.1)	2.2		0.9	918.7
Operating and maintenance	113.8		51.9	11.1	49.9	0.9
General and administrative	49.6	(0.1)	30.6	9.4	6.8	2.9
Production and other taxes	73.2		47.1	24.8	1.1	0.2
Depreciation, depletion and amortization	142.7		107.5	25.1	9.4	0.7
Other operating expenses	29.7		22.2	7.5		
Total operating expenses	908.7	(422.2)	261.5	77.9	68.1	923.4
Net gain on asset sales	0.3		0.1		0.2	
Operating income	276.9		187.4	55.1	31.0	3.4
Interest and other income	1.9	(25.4)	0.9	0.5	0.1	25.8
Income from unconsolidated affiliates	5.1		0.2		4.9	
Interest expense	(27.4)	25.4	(21.7)	(0.9)	(2.8)	(27.4)
Income tax expense	(91.1)		(58.6)	(19.4)	(12.2)	(0.9)
Net income	$ 165.4		$ 108.2	$ 35.3	$ 21.0	$ 0.9
Identifiable assets	$1,966.8		$1,244.4	$ 293.8	$ 217.1	$ 211.5
Investment in unconsolidated affiliates	33.2		0.1		32.6	0.5
Capital expenditures	336.8		263.9	38.9	26.3	7.7
Goodwill	61.5		61.5			

Note 13 – Supplemental Gas and Oil Information (Unaudited)

The Company uses the successful efforts accounting method for its gas and oil exploration and development activities and for cost-of-service gas and oil properties.

Questar E&P Activities

The following information is provided with respect to Questar E&P's gas and oil exploration and production activities, which are all 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,	
	2006	2005
	(in millions)	
Proved properties	**$2,646.6**	$2,047.9
Unproved properties	**42.7**	41.5
Support equipment and facilities	**18.5**	18.4
	2,707.8	2,107.8
Accumulated depreciation, depletion and amortization	**(901.5)**	(731.1)
	$1,806.3	$1,376.7

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. The development costs include expenditures to develop a portion of the proved undeveloped reserves reported at the end of the prior year. These costs were $109.2 million in 2006, $116.7 million in 2005 and $80.1 million in 2004.

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Property acquisition			
Unproved	**$ 22.5**	$13.7	$ 13.3
Proved	**20.6**	3.4	1.2
Exploration (capitalized and expensed)	**34.5**	49.4	25.1
Development	**581.2**	381.7	239.7
	$658.8	$448.2	$279.3

Results of Operation

Following are the results of operation of Questar E&P gas and oil exploration and development activities, before corporate overhead and interest expenses.

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Revenues	**$815.7**	$620.6	$448.8
Production expenses	**131.9**	130.5	99.0
Exploration expenses	**34.4**	11.1	9.2
Depreciation, depletion and amortization	**185.7**	134.7	107.5
Abandonment and impairment	**7.6**	7.7	13.0
Total expenses	**359.6**	284.0	228.7
Revenues less expenses	**456.1**	336.6	220.1
Income taxes	**(170.1)**	(126.6)	(77.5)
Results of operation before corporate overhead and interest expenses	**$286.0**	$210.0	$142.6

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of the Company's proved gas and oil reserves have been prepared by Ryder Scott Company, LP, H. J. Gruy and Associates, Inc. and Netherland, Sewell & Associates, Inc., independent reservoir engineers, in accordance with the SEC's Regulation S-X and SFAS 69 "Disclosures about Oil and Gas Producing Activities." The table below summarizes the changes in the estimated net quantities of proved natural gas, oil and NGL reserves for each of the three years in the period ended December 31, 2006. The quantities reported are based on existing economic and operating conditions at the time the estimates were made. All gas and oil reserves reported are located in the United States. The Company does not have any long-term supply contracts with foreign governments or reserves of equity investees.

	Natural Gas	Oil and NGL	Natural Gas Equivalents
	(Bcf)	(MMbbl)	(Bcfe)[a]
Proved Reserves			
Balance at January 1, 2004	999.2	26.6	1,158.7
Revisions -			
Previous estimates	(16.5)	(0.8)	(21.1)
Pinedale increased-density[b]	302.6	2.4	316.9
Extensions and discoveries	74.2	1.3	82.2
Purchase of reserves in place	0.8		0.8
Production	(89.8)	(2.3)	(103.5)
Balance at December 31, 2004	1,270.5	27.2	1,434.0
Revisions -			
Previous estimates	11.9	(0.7)	7.9
Pinedale increased-density[b]	31.5	0.3	33.0
Extensions and discoveries	110.9	1.4	119.3
Purchase of reserves in place	0.3	0.1	0.7
Sale of reserves in place	(0.3)		(0.3)
Production	(100.0)	(2.4)	(114.2)
Balance at December 31, 2005	1,324.8	25.9	1,480.4
Revisions -			
Previous estimates	(38.9)	2.6	(23.8)
Pinedale increased-density[b]	163.0	1.2	170.4
Extensions and discoveries	119.1	1.2	126.6
Purchase of reserves in place	9.8	0.1	10.2
Sale of reserves in place	(2.7)		(2.8)
Production	(113.9)	(2.6)	(129.6)
Balance at December 31, 2006	**1,461.2**	**28.4**	**1,631.4**
Proved-Developed Reserves			
Balance at January 1, 2004	612.2	20.5	735.2
Balance at December 31, 2004	680.6	21.3	808.3
Balance at December 31, 2005	792.0	21.4	920.5
Balance at December 31, 2006	**852.0**	**23.1**	**990.7**

(a) Natural Gas Equivalents – oil 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.

(b) 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 an improved understanding of Lance Pool reservoir characteristics. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place in the Lance Pool reservoirs at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes.

The Wyoming Oil and Gas Conservation Commission (WOGCC) has approved 10-acre-density drilling for Lance Pool wells on about 12,700 of the Company's 18,208 acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the estimated productive limits of the Company's core acreage in the field. The Company currently believes that up to 932 wells will be required to fully develop the Lance Pool on 10-acre density. The Company will continue to disclose future revisions to proved reserves associated with Pinedale increased-density drilling separately.

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31 using year-end prices and known contract-price changes. The year-end prices do not include any impact of hedging activities. The average year-end price per Mcf of proved natural gas reserves was $4.47 in 2006, $7.80 in 2005 and $5.50 in 2004. The average year-end price per barrel of proved oil and NGL reserves combined was $51.49 in 2006, $56.47 in 2005 and $40.60 in 2004. Year-end production costs, development costs and appropriate statutory income tax rates, with consideration of future tax rates already legislated, 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 $219.2 million in 2007, $217.9 million in 2008 and $159.7 million in 2009. At the end of this three-year period the Company expects to have evaluated about 53% of the cu rrent booked proved undeveloped reserves.

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 usefulness of the standardized measure of future net cash flows is impaired because of the reliance on reserve estimates and production schedules that are inherently imprecise.

Management considers a number of factors when making investment and operating decisions. They include estimates of probable and proved reserves and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Future cash inflows	**$ 7,985.1**	$11,791.1	$ 8,090.0
Future production costs	**(2,133.0)**	(2,465.8)	(1,827.4)
Future development costs	**(1,026.9)**	(725.7)	(663.1)
Future income tax expenses	**(1,396.2)**	(2,930.3)	(1,854.5)
Future net cash flows	**3,429.0**	5,669.3	3,745.0
10% annual discount to reflect timing of net cash flows	**(1,861.2)**	(2,962.2)	(1,984.5)
Standardized measure of discounted future net cash flows	**$ 1,567.8**	$ 2,707.1	$ 1,760.5

The principal sources of change in the standardized measure of discounted future net cash flows were:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Beginning balance	**$2,707.1**	$1,760.5	$1,530.0
Sales of gas and oil produced, net of production costs	**(683.8)**	(490.1)	(349.8)
Net changes in prices and production costs	**(1,994.3)**	1,183.6	(199.5)
Extensions and discoveries, less related costs	**233.1**	330.4	150.7
Revisions of quantity estimates	**269.9**	113.3	542.3
Net purchases and sales of reserves in place	**(7.5)**	0.5	(0.2)
Cost to develop proved undeveloped reserves	**109.2**	116.7	80.1
Change in future development	**(259.6)**	(120.3)	(203.6)
Accretion of discount	**411.0**	176.1	153.0
Net change in income taxes	**760.8**	(440.3)	(29.0)
Other	**21.9**	76.7	86.5
Net change	**(1,139.3)**	946.6	230.5
Ending balance	**$1,567.8**	$2,707.1	$1,760.5

Cost-of-Service Activities

The following information is provided with respect to cost-of-service gas and oil properties managed and developed by Wexpro and regulated by the Wexpro Agreement. Information on the standardized measure of future net cash flows has not been included for cost-of-service activities because the operations of and return on investment for such properties are regulated by the Wexpro Agreement.

Capitalized Costs

Capitalized costs for cost-of-service gas and oil properties net of the related accumulated depreciation and amortization are shown below.

	December 31,	
	2006	2005
	(in millions)	
Wexpro	**$353.2**	$283.9
Questar Gas	**13.2**	14.4
	$366.4	$298.3

Costs Incurred

Costs incurred by Wexpro for cost-of-service gas and oil-producing activities were $100.3 million in 2006, $57.0 million in 2005 and $43.6 million in 2004.

Results of Operation

Following are the results of operation of cost-of-service gas and oil-development activities, before corporate overhead and interest expenses:

	Year Ended December 31,		
	2006	2005	2004
	(in millions)		
Revenues			
From unaffiliated companies	**$ 19.7**	$ 21.7	$ 17.3
From affiliates – Note A	**150.5**	132.3	115.6
Total revenues	**170.2**	154.0	132.9
Production expenses	**50.5**	50.0	40.6
Depreciation and amortization	**33.1**	26.9	25.0
Abandonment and impairment		0.2	2.8
Exploration		0.4	
Total expenses	**83.6**	77.5	68.4
Revenues less expenses	**86.6**	76.5	64.5
Income taxes	**(29.6)**	(26.8)	(23.2)
Results of operation before corporate overhead and interest expense	**$ 57.0**	$ 49.7	$ 41.3

Note A – Primarily represents revenues received from Questar Gas pursuant to the Wexpro Agreement.

Estimated Quantities of Cost-of-Service Proved Gas and Oil Reserves

Since the gas reserves operated by Wexpro are delivered to Questar Gas at cost-of-service, SEC guidelines with respect to standard economic assumptions are not applicable. The SEC anticipated this potential difficulty and provides that companies may give appropriate recognition to differences arising because of the effect of the ratemaking process. Accordingly, Wexpro uses a minimum-producing rate or maximum well-life limit to determine the ultimate quantity of reserves attributable to each well. The following estimates were made by the Wexpro's reservoir engineers:

	Natural Gas	Oil and NGL	Natural Gas Equivalents
	(Bcf)	(MMbbl)	(Bcfe)
Proved Reserves			
Balance at January 1, 2004	434.4	3.6	455.9
Revisions -			
Previous estimates	4.5		4.7
Pinedale increased-density[(a)]	112.7	0.9	118.3
Extensions and discoveries	18.3	0.1	18.7
Production	(38.8)	(0.4)	(41.3)
Balance at December 31, 2004	531.1	4.2	556.3
Revisions-			
Previous estimates	(30.8)	(0.1)	(32.2)
Pinedale increased-density	7.8		8.1
Extensions and discoveries	29.2	0.2	30.7
Production	(40.0)	(0.4)	(42.4)
Balance at December 31, 2005	497.3	3.9	520.5
Revisions-			
Previous estimates	22.3	(0.1)	21.5

Pinedale increased-density	100.0	0.8	104.6
Extensions and discoveries	39.8	0.2	41.3
Production	(38.8)	(0.4)	(40.9)
Balance at December 31, 2006	**620.6**	**4.4**	**647.0**
Proved-Developed Reserves			
Balance at January 1, 2004	406.1	3.3	426.1
Balance at December 31, 2004	409.2	3.2	428.4
Balance at December 31, 2005	406.6	3.1	425.2
Balance at December 31, 2006	**440.6**	**2.9**	**458.2**

(a) The area approved by the WOGCC for 10-acre-density drilling of Lance Pool wells corresponds to the estimated productive limits of the Company's core acreage in the field. The Company will continue to disclose future revisions to proved reserves associated with Pinedale increased-density drilling separately.

QUESTAR MARKET RESOURCES, INC.
Schedule of Valuation and Qualifying Accounts

Column A Description	Column B Beginning Balance	Column C Amounts charged to expense	Column D Deductions for accounts written off	Column E Ending Balance
	(in millions)			
Year Ended December 31, 2006				
Allowance for bad debts	**$2.9**	**$1.4**		**$4.3**
Year Ended December 31, 2005				
Allowance for bad debts	2.8	0.1		2.9
Year Ended December 31, 2004				
Allowance for bad debts	4.1	(0.7)	(0.6)	2.8

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

The Company has not changed its independent auditors or had any disagreement with them concerning accounting matters and financial statement disclosures within the last 24 months.

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 (the Exchange Act)) as of the end of the period covered by the report (the Evaluation Date). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company, including its consolidated subsidiaries, required to be included in the Company's reports filed or submitted under the Exchange Act. The Company's Chief Executive Officer and Chief Financial Officer also concluded that the controls and procedures were effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is ac cumulated and communicated to the

Company's management including its principal executive and financial officers or persons performing similar functions as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls.

Since the Evaluation Date, there have not been any changes in the Company's internal controls or other factors during the most recent fiscal quarter that could materially affect such controls.

ITEM 9B. OTHER INFORMATION.

None.

PART III

The Company, as a wholly owned subsidiary of a reporting company under the Act, is entitled to omit all information requested in Part III, Items 10-13.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

Ernst & Young, LLP, serves as the independent registered public accounting firm for Questar and its subsidiaries including the Company. The following table lists the fees billed by Ernst & Young to Questar for services and the fees billed directly to the Company or allocated to the Company as a member of Questar's consolidated group:

	2006	2005
Audit Fees	**$1,392,407**	$1,148,183
Market Resources Portion	**824,370**	596,733
Audit-related Fees	**90,000**	48,500
Market Resources Portion	**44,647**	23,750
Tax Fees	**5,545**	9,008
Market Resources Portion	**2,751**	4,441
All Other Fees	-	-
Market Resources Portion	-	-

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

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
1.1.*	Purchase Agreement, dated May 11, 2006, by and among Questar Market Resources, Inc., and named Underwriters. (Incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 11, 2006.)
3.1.*	Articles of Incorporation dated April 27, 1988, for Utah Entrada Industries, Inc. (Exhibit No. 3.1. to the Company's Form 10 dated April 12, 2000.)
3.2.*	Articles of Merger dated May 20, 1988, of Entrada Industries, Inc., a Delaware corporation and Utah Entrada Industries, Inc, a Utah corporation. (Exhibit No. 3.2. to the Company's Form 10 dated April 12, 2000.)

3.3.* Articles of Amendment dated August 31, 1998, changing the name of Entrada Industries, Inc. to Questar Market Resources, Inc. (Exhibit No. 3.3. to the Company's Form 10 dated April 12, 2000.)

3.4.* Bylaws, as amended effective February 8, 2005, (Exhibit No. 3.4. to the Company's Annual Report on Form 10-K for 2004.)

4.1.*[1] Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. and Bank One, NA, as Trustee for the Company's Notes. (Exhibit No. 4.01. to the Company's Current Report on Form 8-K dated March 6, 2001.)

4.2.* Credit Agreement dated March 19, 2004, by and among the Company, Bank of America, N.A. and other lenders. (Exhibit No. 4.4. to the Company's Annual Report on Form 10-K for 2003.)

4.3.* Form of the Registrant'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 11, 2006.)

4.4.* Form of Officers' Certificate setting forth the terms of the 6.05% Notes. (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 11, 2006.)

10.1.* Stipulation and Agreement dated October 14, 1981, executed by Mountain Fuel Supply Company [Questar Gas Company]; Wexpro Company; the Utah Department of Business Regulations, Division of Public Utilities; the Utah Committee of Consumer Services; and the staff of the Public Service Commission of Wyoming. (Exhibit No. 10(a) to Questar Gas Company's Form 10-K Annual Report for 1981.)

10.2.* First Amendment to Credit Agreement dated October 25, 2004, by and among the Company, Bank of America, N.A. and other lenders. (Exhibit No. 4.5. to the Company's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2004.)

10.3.* Second Amendment to Credit Agreement dated August 9, 2005, by and among Questar Market Resources, Inc., Bank of America, N.A. and other lenders. (Exhibit No. 4.4. to the Company's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2005.)

10.4.* Third Amendment to Credit Agreement dated September 20, 2005, by and among Questar Market Resources, Inc., Bank of America, N.A. and other lenders. (Exhibit No. 4.5. to the Company's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2005.)

10.5.* Fourth Amendment to Credit Agreement dated July 27, 2006, by and among Questar Market Resources, Inc., Bank of America, N.A. and other lenders. (Exhibit No. 10.1 to the Company's Quarterly Report on Form 10-Q for quarter ended June 30, 2006.)

12. Ratio of earnings to fixed charges.

24. Power of Attorney.

31.1. Certification signed by Charles B. Stanley, Questar Market Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2. Certification signed by S. E. Parks, Questar Market Resources, Inc. Vice President and Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32. Certification signed by Charles B. Stanley and S. E. Parks, Questar Market Resources, Inc. President and Chief Executive Officer and Vice President and Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Exhibits so marked have been filed with the Securities and Exchange Commission as part of the referenced filing and are incorporated herein by reference.

[1]Wells Fargo Bank, N.A. serves as the successor trustee.

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 2nd day of March, 2007.

QUESTAR MARKET 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/S. E. Parks S. E. Parks	Vice President and Chief Financial Officer (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
*Teresa Beck	Director
*R. D. Cash	Director
*L. Richard Flury	Director
*James A. Harmon	Director
*Robert E. McKee III	Director
*M. W. Scoggins	Director
*C. B. Stanley	Director

March 2, 2007
Date

*By /s/C. B. Stanley
C. B. Stanley, Attorney in Fact

Exhibits List

Exhibit No.	Description
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3.4.*	Bylaws, as amended effective February 8, 2005, (Exhibit No. 3.4. to the Company's Annual Report on Form 10-K for 2004.)
4.1.*[1]	Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. and Bank One, NA, as Trustee for the Company's Notes. (Exhibit No. 4.01. to the Company's Current Report on Form 8-K dated March 6, 2001.)
4.2.*	Credit Agreement dated March 19, 2004, by and among the Company, Bank of America, N.A. and other lenders. (Exhibit No. 4.4. to the Company's Annual Report on Form 10-K for 2003.)
4.3.*	Form of the Registrant'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 11, 2006.)
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12.	Ratio of earnings to fixed charges.

24. Power of Attorney.

31.1. Certification signed by Charles B. Stanley, Questar Market Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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32. Certification signed by Charles B. Stanley and S. E. Parks, Questar Market Resources, Inc. President and Chief Executive Officer and Vice President and Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Exhibits so marked have been filed with the Securities and Exchange Commission as part of the referenced filing and are incorporated herein by reference.

[1]Wells Fargo Bank, N.A. serves as the successor trustee.

Exhibit 12.

Questar Market Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,		
	2006	2005	2004
	(dollars in millions)		
Earnings			
Income before income taxes	**$562.7**	$408.3	$256.5
Less Company's share of earnings of Equity investees	**(7.5)**	(7.5)	(5.1)
Plus distributions from equity investees	**7.1**	10.0	8.3
Plus minority interest in income			0.3
Plus interest expense	**33.9**	30.9	27.4
Plus interest portion of rental expense	**1.2**	1.1	1.1
	$597.4	$442.8	$288.5
Fixed Charges			
Interest expense	**$ 33.9**	$ 30.9	$ 27.4
Plus interest portion of rental expense	**1.2**	1.1	1.1
	$ 35.1	$ 32.0	$ 28.5
Ratio of Earnings to Fixed Charges	**17.0**	13.8	10.1

For purposes of this presentation, earnings represent income before income taxes adjusted for fixed charges, earnings and distributions of equity investees. Income before income taxes includes Market Resources share of pretax earnings of equity investees. Fixed charges consist of total interest charges (expensed and capitalized), amortization of debt issuance costs, and the interest portion of rental expense estimated investees.

Exhibit 24.

POWER OF ATTORNEY

We, the undersigned directors of Questar Market Resources, Inc., hereby severally constitute C. B. Stanley and S. E. Parks, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2006 and any and all amendments to be filed with the Securities and Exchange Commission by Questar Market Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2006 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ K. O. Rattie	Chairman of the Board	2-13-07
/s/ C. B. Stanley	President and Chief Executive Officer Director	2-13-07
/s/ Phillips S. Baker	Director	2-13-07
/s/ Teresa Beck	Director	2-13-07
/s/ R. D. Cash	Director	2-13-07
/s/ L. Richard Flury	Director	2-13-07
/s/ James A. Harmon	Director	2-13-07
/s/ Robert E. McKee	Director	2-13-07
/s/ M. W. Scoggins	Director	2-13-07

Exhibit 31.1.

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this report of Questar Market Resources, Inc. on Form 10-K for the period ending December 31, 2006;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2007

/s/Charles B. Stanley
Charles B. Stanley
President and Chief
Executive Officer

Exhibit 31.2.

CERTIFICATION

I, S. E. Parks, certify that:

1. I have reviewed this report of Questar Market Resources, Inc. on Form 10-K for the period ending December 31, 2006;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2007

/s/S. E. Parks
S. E. Parks
Vice President and Chief
Financial Officer

Exhibit 32.

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Questar Market Resources, Inc. (the Company) on Form 10-K for the period ending December 31, 2006, as filed with the Securities and Exchange Commission on the date hereof (the Report), Charles B. Stanley, President and Chief Executive Officer of the Company, and S. E. Parks, Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

QUESTAR MARKET RESOURCES, INC.

March 2, 2007

/s/Charles B. Stanley
Charles B. Stanley
President and Chief Executive Officer

March 2, 2007

/s/S. E. Parks
S. E. Parks
Vice President and Chief
Financial Officer