SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2004** OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM _____ TO _____.

Commission File No. 0-30321

QUESTAR MARKET RESOURCES, INC.

(Exact name of registrant as specified in its charter)

State of Utah	87-0287750
(State or other jurisdiction of incorporation or organization)	(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)	(Zip code)
Registrant’s telephone number, including area code:	(801) 324-2600

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act)
Yes ___ No ___

Aggregate market value of the voting common equity held by non-affiliates of the registrant computed by reference to the price at which the common equity was last sold as of the last business day of the registrant’s most recently completed second quarter (June 30, 2004): $0.

On February 28, 2005, 4,309,427 shares of the registrant’s Common Stock, $1.00 par value. (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 10-K Report with the reduced disclosure format.

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FORWARD-LOOKING STATEMENTS

This report includes “forward-looking statements” within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act (Act) of 1934 as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding the Company’s future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as “may,” “will,” “could,” “expect,” “intend,” “project,” “estimate,” “anticipate,” “believe,” “forecast,” or “continue” or the negative thereof or variations thereon or similar terminology. Although these statements are made in good faith and are reasonable representations of Questar Market Resources, Inc. (Market Resources or the Company) expected performance at the time, actual results may vary from management’s stated expectations and projections due to a variety of factors.

Important assumptions and other significant factors that could cause actual results to differ materially from those expressed or implied in forward-looking statements include:

Market Resources subsidiaries find, produce, and sell natural gas, oil and NGL. Natural gas, oil and NGL prices are volatile and, therefore, Market Resources revenues, cash flow and earnings can be volatile. The Company cannot predict future natural gas, oil and NGL price movements, which are subject to forces beyond our control such as:

- Domestic and foreign supply of natural gas and oil;
- Regional basis due to pipeline-capacity constraints;
- Domestic and global economic conditions;
- Weather;
- Domestic and foreign government regulations;
- The price and availability of alternative fuels;
- The price and availability of drilling rigs and other materials and services.

The Company uses financial contracts to hedge its 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. While hedging reduces the impact of declining prices, it may also limit future revenues from favorable price movements. Market Resources believes its Wexpro subsidiary generates revenues that are not significantly sensitive to short-term fluctuations in natural gas and oil prices.

Market Resources’ profitability depends not only on prevailing prices for natural gas, oil and NGL, but also the Company’s ability to find, develop and acquire gas and oil reserves that are economically recoverable. Substantial capital expenditures are required to find, develop and acquire gas and oil reserves to replace those depleted by production.

Questar Exploration and Production’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 estimates of future net revenues from proved reserves and the present value of those reserves are based upon certain assumptions about production levels, prices and costs, which may change. The volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The meaningfulness of such estimates depends on the accuracy of the assumptions upon which they were based. Actual results may differ materially from the estimated results.

Drilling is a high-risk activity. Operating risks include: blow-outs; fire; unexpected drilling conditions such as uncontrollable flows of gas, oil, formation water or drilling fluids; abandonment costs; explosions; pipe, cement or casing failures; oil spills; natural gas leaks; pipeline ruptures; and discharges of toxic gases. The Company could incur substantial losses as a result of injury or loss of life; environmental damage; destruction of property; fines; or curtailment of operations. The Company maintains insurance against some, but not all, of these potential risks and losses.

Market Resources’ subsidiaries are 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, the Company may incur substantial costs 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 and its subsidiaries must comply with numerous and complex regulations governing their 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 tend to become more stringent over time, and can limit or prevent the Company from exploring for, finding and producing natural gas and oil on its Rockies leasehold. Certain environmental groups oppose drilling on some of the Company's federal and state leases.

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; effects of accounting policies issued periodically by accounting standard-setting bodies; terrorist attacks or acts of war; changes in the business or financial condition of the Company; changes in credit ratings; and availability of financing.

FORM 10-K
ANNUAL REPORT, 2004

PART I

ITEM 1. BUSINESS.

General

Questar Market Resources Inc., (Market Resources or the Company) is a wholly owned subsidiary of Questar Corporation (Questar) and is the primary growth driver within Questar. Market Resources has four major subsidiaries: Questar Exploration & Production (Questar E&P) acquires, explores for, develops and produces gas and oil; Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas Company (Questar Gas); Questar Gas Management Company (Gas Management) provides 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 through its limited liability company (LLC), Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir.

See Note 12 in Item 8. of this report for financial information concerning Market Resources' lines of business that contribute 10% or more of consolidated revenues.

Glossary of Commonly Used Terms

bbl Barrel, which is equal to 42 United States gallons and is a common unit of measurement of crude oil.

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

bcf One billion cubic feet, a common unit of measurement of natural gas.

bcfe One billion cubic feet of natural gas equivalent. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.

btu One British thermal unit – a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

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 14.73 pounds per square inch).

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

dew point 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.
exploratory well	A well drilled into a previously untested geologic prospect to determine the presence of gas or oil.
finding costs	Finding costs are the sum of costs incurred for gas and oil exploration and development activities; including 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 of previous estimates, and purchases in-place for the same period. The Company expresses finding costs in dollars per Mcfe averaged over a five-year period. See Note 13 included in Item 8. of this report for additional details.
futures contract	An exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.
gas	All references to “gas” in this report refer to natural gas.
gross	“Gross” natural gas and oil wells or “gross” acres equal 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.
Mbbl	One thousand barrels.
Mcf	One thousand cubic feet.
Mcfe	One thousand cubic feet of natural gas equivalents. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.
Mdth	One thousand decatherms.
Mdthe	One thousand decatherm equivalents. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.
MMbbl	One million barrels.
MMBtu	One million British thermal units.
MMcf	One million cubic feet.
MMcfe	One million cubic feet of natural gas equivalents.
MMdth	One million decatherms.
MMgal	One million U. S. gallons.
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.
production-replacement ratio	The production-replacement ratio is calculated by dividing the net-proved reserves added through discoveries, positive and negative revisions of previous estimates, 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)(2i)(2ii)(2iii) for a complete definition.
proved-developed reserves	Reserves that include proved developed-producing reserves and proved-developed behind-pipe 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 separate from other reservoirs.
wet gas	Unprocessed natural gas that contains a mixture of heavier hydrocarbons including ethane, propane, butane, and natural gasoline.
working interest	An interest that gives the owner the right to drill, produce, and conduct operating activities on a property and receive a share of any production.

SEC Filings and Website Information

Market Resources files annual, quarterly, and current reports with the Securities and Exchange Commission (SEC). Interested parties can read and copy any materials filed with the SEC at its Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549, and can obtain information about the operations of the Public Reference Room by calling the SEC at 1-800-SEC-0300. The SEC also maintains a website that contains information filed electronically that can be accessed over the Internet at www.sec.gov.

Investors can also access financial and other information for Market Resources through Questar's website at www.questar.com. Questar's website contains Statements of Responsibility for Board Committees, Corporate Governance Guidelines and its Business Ethics Policy.

Market Resources makes available, free of charge, through the Questar website, copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports. Access to these reports is provided as soon as reasonably practicable after such reports are electronically filed with the SEC.

Narrative Description of Business

Market Resources is a natural gas-focused energy company. The following descriptions should be read in conjunction with Item 7. of this report.

Market Resources, General

Market Resources is Questar's primary growth driver. Market Resources has four major subsidiaries: Questar E&P acquires, explores for, develops and produces gas and oil; Wexpro manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas; Gas Management provides 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 Clear Creek Storage Company, LLC, operates an underground gas-storage reservoir.

Questar E&P, General

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 at properties near Pinedale, Wyoming, and in the Uinta Basin of Utah. Questar E&P continues to conduct exploratory drilling to determine commerciality of its inventory of undeveloped leaseholds located primarily in the Rocky Mountain region, including assessment of deeper reservoirs beneath currently producing horizons. In the Midcontinent, Questar E&P has several active development projects, including an ongoing coalbed methane-development project in eastern Oklahoma and a tight-sands gas-development project in northwest Louisiana. Questar E&P seeks to maintain geographical and geological diversity with its two core regions. Questar E&P has in the past and may in the future pursue acquisition of producing properties through purchase of assets or corporate entities to expand its presence in its core areas or create a new core area.

Questar E&P increased year-end 2004 proved reserves 24% to 1,434 bcfe versus 1,159 bcfe at the end of 2003. Reserve additions included a 295 bcfe net increase at Pinedale related primarily to the approval of 20-acre well spacing.

Questar E&P's primary focus is natural gas. Natural gas comprised about 88.6% of Questar E&P's proved reserves. Approximately 56% of year-end 2004 total-proved reserves were classified as proved developed producing. The largest concentration of proved-undeveloped reserves is at the Pinedale development project, where approximately 541 bcfe are classified as proved undeveloped.

E&P, Risk Management

Questar E&P focuses primarily on lower-risk development drilling. In addition Market Resources has established policies and procedures for managing commodity-price risks through the use of derivatives. Market Resources hedges commodity prices to support credit ratings and to protect returns on invested capital, cash flow and earnings from downward movements in commodity prices. However, these arrangements usually limit future gains from favorable price movements. Market Resources may hedge up to 100% of its production from proved-developed reserves when commodity prices are attractive. Market Resources also manages market-access risk by building the necessary infrastructure, particularly gathering and processing facilities, to move company production to an interstate pipeline. See Item 7A. for more information.

The availability of regional pipeline capacity can also significantly affect gas prices. The Rocky Mountain region is the fastest growing major producing region in the United States. Regional gas production exceeds regional gas consumption, particularly during the nonheating season. Only about 20% of the gas produced in the Rockies is consumed by local markets. When Rockies production exceeds available pipeline capacity, Rockies basis – the difference between gas prices at the Henry Hub (the national market benchmark) and sales prices in the Rockies – widens, resulting in lower realized prices for producers. The expansion of the Kern River Pipeline in May 2003 added 0.9 bcf of daily capacity from the Rocky Mountain area to markets in the western United States. This expansion helped alleviate a transportation shortfall that adversely affected Rockies gas prices though much of 2002 and the first half of 2003. The start-up in 2005 of a new 0.56-bcf-per-day pipeline, connecting Cheyenne, Wyoming to Greensburg, Kansas, may reduce basis risk for Rockies producers but also increase basis risk for Midcontinent producers.

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 pipelines, gas-marketing firms, industrial users and local-distribution companies. Energy Trading regularly evaluates counterparty credit and may require financial guarantees from parties that fail to meet its credit criteria. Energy Trading sells company 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.

E&P, Regulation

Questar E&P's 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. During the last two years, Questar E&P has been working 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 the habitat. 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. Some species that are known to be present may be listed under federal law as endangered or threatened. Such listing could have a material impact on access to Market Resources leaseholds in certain areas or during periods when the particular species is present. For example, the sage grouse was recently considered by the U.S. Fish and Wildlife Service for listing as a threatened and/or endangered species. The sage grouse is known to be present in certain areas of the Rocky Mountains, in western Wyoming and Colorado, including the company's Pinedale leaseholds. On January 7, 2005, after several years of study, the U.S. Fish and Wildlife Service determined not to list the sage grouse as threatened and/or endangered, in large part due to adoption of aggressive management plans by various state and federal agencies to protect the species and its habitat. Such management plans could impact Market Resources activities.

Most recently, a petition has been filed seeking protection of the pygmy rabbit, another sage brush obligate, as a threatened and/or endangered species. The U.S. Fish and Wildlife Service is in the initial 90-day review process to determine if information in the petition presents substantial scientific or commercial information that the petitioned action (threatened and/or endangered species listing) is warranted. The range of the pygmy rabbit is thought to include portions of Wyoming and Colorado where Market Resources is active.

Wexpro, General

Wexpro has generated steady growth and predictable earnings through a business model that is unique in the energy industry. Wexpro develops gas and oil on certain producing properties for Questar Gas, an affiliated company, under the terms of a comprehensive agreement, the Wexpro Agreement. Under the Wexpro Agreement, Wexpro recovers its costs plus a return on its investment. See Note 10 in Item 8. of this 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. Wexpro production and managed reserves are not included in Questar E&P production and reserves. Wexpro managed cost-of-service gas, plus the gas attributable to royalty-interest owners, satisfied 47% of Questar Gas's system requirements during 2004 at a cost of service lower than Questar Gas's average cost for field-purchased gas.

Wexpro also owns oil-producing properties. Under terms of the Wexpro Agreement, Wexpro recovers its operating expenses and earns a return on its investment in successful oil wells and associated equipment from crude oil sales revenues. Surplus revenues, after recovery of expenses and Wexpro's return on investment, are divided between Wexpro (46%) and Questar Gas (54%).

Wexpro Regulations

Wexpro's gas- and oil-development and production activities are subject to the same type of regulation as Questar E&P. Wexpro is also subject to oversight by the Utah Division of Public Utilities. The division retains an independent consultant to monitor the prudence of Wexpro's activities.

Gas Management, General

Gas Management provides gas-gathering and processing services to affiliates and third-party producers, primarily in the Rocky Mountain region. Gas Management also owns 50% of Rendezvous Gas Services, LLC (Rendezvous), a joint venture that operates gas-gathering facilities in western Wyoming. Rendezvous gathers natural gas for Pinedale Anticline and Jonah producers for delivery to various interstate pipelines. Rendezvous plans to build a new gathering line from Blacks Fork plant to a connection with the Kern River Pipeline. Under a contract with Questar Gas, Gas Management gathers cost-of-service volumes produced from properties operated by Wexpro.

Gas Management's processing margins are based on the difference between the market price for natural gas and the market value of the NGL extracted from the gas stream (commonly referred to as the "frac spread"). Gas Management may hedge NGL prices to protect processing margins. To reduce 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 NGL- and gas-price risk while a fee-based contract eliminates commodity-price risk for the plant owner.)

Energy Trading, General

Energy Trading markets natural gas, oil and NGL. It combines gas volumes purchased from third parties and equity production (production from affiliates) to build a flexible and reliable portfolio. As a wholesale-marketing entity, Energy Trading concentrates on markets in the Pacific Northwest, Rocky Mountains and Midwest 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 Questar Pipeline Company (Questar Pipeline), an affiliated company.

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 company production. Energy Trading does not engage in speculative hedging transactions. See Notes 1 and 5 included in Item 8. and Item 7A. of this report for additional information relating to hedging activities.

Energy Trading pays Questar E&P index prices for production volumes on which the latter calculates and pays royalties. Energy Trading then resells such volumes and bears profit-and-loss risk. In addition to contracting for storage capacity at Clay Basin, Energy Trading, through Clear Creek Storage Company, LLC, operates an underground gas-storage reservoir in southwestern Wyoming. It uses owned and leased-storage capacity together with firm-transportation capacity to take advantage of price differentials and arbitrage opportunities.

Rocky Mountain producers, marketers and end-users seek capacity on transmission systems that move gas to California (Kern River), the Pacific Northwest (Northwest Pipeline) or Midwestern markets (WIC, Colorado Interstate Gas). Questar Pipeline provides access for many producers to these third-party pipelines. Some parties, including Gas Management, are building gathering lines that allow producers to make direct connections to competing pipeline systems.

Environmental Matters

See Item 3. Legal Proceedings in this report for a discussion of the Company's environmental matters.

Employees

At December 31, 2004, Market Resources had 563 employees in the United States compared with 535 at year-end 2003. None of these employees are represented under collective bargaining agreements. The Company also periodically engages independent reservoir-engineering consultants and other technical specialists on a fee basis.

ITEM 2. PROPERTIES.

Exploration and Production

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, 2004. The U.S. reserves were collectively estimated by Ryder Scott Company; Netherland, Sewell & Associates, Inc.; H. J. Gruy and Associates, Inc. and Malkewicz Hueni Associates Inc., independent reservoir-engineering consultants. Estimates of Canadian reserves, sold in 2002, were prepared by Gilbert Laustsen Jung Associates Ltd, and Sproule Associates Limited, independent reservoir-engineering consultants. Questar E&P does not have any long-term supply contracts with foreign governments or reserves of equity investees or of subsidiaries with a significant minority interest. All properties are located in the United States.

Estimated proved reserves	
Natural gas (bcf)	1,270.5
Oil and NGL (MMbbl)	27.2
Total proved reserves (bcfe)	1,434.0
Proved developed reserves (bcfe)	808.3
Estimated future net revenues before future income taxes (in thousands) (1)	$5,599,487
Standardized measure of discounted net cash flows (in thousands) (2)	$1,760,538

(1) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, using average year-end 2004 prices of $5.50 per Mcf for natural gas and $40.60 per bbl for oil and NGL combined, net of estimated production and development costs (but excluding the effects of general and administrative expenses; debt services; depreciation, depletion and amortization; and income tax expense).

(2) The standardized measure of discounted net cash flows prepared by the Company represent 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 producer.

Questar E&P's proved reserve statistics for the years ended December 31, 2000, through 2004, are summarized below.

Estimated Proved Reserves, Annual Production, and Reserve Life*

Year	Est. Year-End Proved Reserves (bcfe)	Annual Production (bcfe)	Reserve Life (Years)
2000	730.1	82.3	8.9
2001	1,184.4	85.6	13.8
2002	1,113.4	96.3	11.6
2003	1,158.7	92.8	12.5
2004	1,434.0	103.5	13.9

*Includes reserves and production information for Canadian properties sold in the fourth quarter of 2002.

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. These non-GAAP measures provide useful information to investors interested in analyzing Questar E&P performance, but may not be directly comparable with similar information disclosed by other gas and oil companies.

In 2004 gas and oil reserves increased 24%, after production and sales of producing properties, to 1,434 bcfe versus a 4% increase in 2003 to 1,159 bcfe. Questar E&P's production-replacement ratio was 366% in 2004 and 149% in 2003. Net reserve additions, revisions, purchases and sales in place totaled 379 bcfe in 2004 and 138 bcfe in 2003. Questar E&P's five-year average finding cost of proved reserves per Mcfe was $0.83, $0.84 and $0.85 in 2004, 2003 and 2002, respectively. The 66% increase in reserves at the Pinedale Anticline was attributable to the 20-acre downspacing.

Questar E&P's estimated proved reserves by major operating areas at December 31, 2004 and 2003 follow.

	2004	2003

	(bcfe)	(of total)	(bcfe)	(of total)
Rocky Mountains				
Pinedale Anticline	737.9	51%	443.2	38%
Uinta Basin	272.4	19%	303.3	26%
Other Rocky Mountains	137.2	10%	133.0	12%
Subtotal – Rocky Mountains	1,147.5	80%	879.5	76%
Midcontinent	286.5	20%	279.2	24%
Total	1,434.0	100%	1,158.7	100%

Reserves – Cost-of-Service. The following table sets forth (i) Questar Gas's estimated proved cost-of-service proved natural gas reserves (which are managed, developed and produced by Wexpro under the terms of the Wexpro Agreement); and (ii) Wexpro's estimated proved-oil reserves (the income from which is shared with Questar Gas pursuant to the terms of the Wexpro Agreement). The estimates were made by Wexpro's reservoir engineers as of December 31, 2004. All properties are located in the United States.

Estimated cost-of-service proved reserves	
Natural gas (bcf)	531.1
Oil (MMbbl)	4.2
Total proved reserves (bcfe)	556.3
Proved-developed reserves (bcfe)	428.4

Since the gas reserves managed by Wexpro are delivered to Questar Gas at cost of service, and any net income from oil properties remaining after recovery of expenses and Wexpro's contractual return on investment under the Wexpro Agreement is divided between Wexpro and Questar Gas, 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's 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 included in Item 8. of this report for additional information pertaining to both Questar E&P's proved reserves and the cost-of-service reserves managed by Wexpro 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, 2004, 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 gas, per barrel of oil and of NGL produced, and the production cost per Mcfe. Production costs include direct-lifting costs (labor, repairs and maintenance, materials, supplies and workovers), administrative costs of production offices, insurance and property and severance taxes, but are exclusive of depreciation and depletion applicable to capitalized-lease acquisitions, exploration and development expenditures. Questar E&P's Canadian properties were sold in the last quarter of 2002.

	Year Ended December 31,		
	2004	2003	2002
United States (excluding cost-of-service production)			
Volumes produced and sold			
Gas (bcf)	89.8	78.8	74.9
Oil and NGL (MMbbl)	2.3	2.3	2.3
Average realized price (including hedges)			
Gas (per Mcf)	$ 4.18	$ 3.62	$ 2.61
Oil and NGL (per bbl)	30.97	23.39	20.26
Production costs per Mcfe			
Lease-operating expense	$ 0.50	$ 0.49	$ 0.51
Production taxes	0.46	0.34	0.20
Production cost	$ 0.96	$ 0.83	$ 0.71

	Year Ended December 31,		
	2004	2003	2002
Canada (in U.S. dollars)			
Volumes produced and sold			
Gas (bcf)			4.8
Oil and NGL (MMbbl)			0.5

Average realized price (including hedges)			
Gas (per Mcf)			$ 2.22
Oil and NGL (per bbl)			21.03
Production costs per Mcfe			
Lease-operating expense			$ 0.92
Production cost			0.92
Cost of Service (Wexpro managed)			
Volumes produced			
Gas (bcf)	38.8	40.1	41.2
Oil and NGL (MMbbl)	0.4	0.4	0.5

Productive Wells. The following table summarizes Market Resources' productive wells (including the cost-of-service wells managed by Wexpro) as of December 31, 2004. All of these wells are located in the United States.

		Gas	Oil	Total
Productive Wells	Gross	3,893	926	4,819
	Net	1,819.0	450.3	2,269.3

Although many 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 2004, there were 63 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, 2004. "Undeveloped Acreage" includes (i) leasehold interests that already may have been classified as containing proved undeveloped reserves; and (ii) 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, 2004

	Developed (1)		Undeveloped (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arizona			480	450	480	450
Arkansas	31,720	10,146	3	1	31,723	10,147
California	345	113	1,613	303	1,958	416
Colorado	161,391	113,832	193,614	101,212	355,005	215,044
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	13,397	16,880	3,843	47,182	17,240
Kentucky			17,323	6,669	17,323	6,669
Louisiana	12,459	11,323	756	756	13,215	12,079
Michigan	89	8	6,240	1,262	6,329	1,270
Minnesota			313	104	313	104
Mississippi	2,904	1,922	1,053	447	3,957	2,369
Montana	20,149	8,541	300,339	53,655	320,488	62,196
Nevada	320	280	680	543	1,000	823
New Mexico	79,433	55,807	38,422	17,650	117,855	73,457
North Dakota	4,635	546	146,364	21,781	150,999	22,327
Ohio			202	43	202	43
Oklahoma	1,483,255	260,409	65,831	38,740	1,549,086	299,149
Oregon			43,869	7,671	43,869	7,671
South Dakota			204,398	107,829	204,398	107,829
Texas	149,253	58,640	39,668	36,401	188,921	95,041
Utah	90,815	79,505	233,673	111,849	324,488	191,354
Washington			26,631	10,149	26,631	10,149
West Virginia	969	115			969	115
Wyoming						
	231,973	150,600	413,608	263,147	645,581	413,747

Total	2,300,184	765,223	1,812,232	799,799	4,112,416	1,565,022

(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.

Substantially all 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 Acreage Expiring	
	Gross	Net
12 Months Ending December 31,		
2005	70,330	47,784
2006	90,420	64,716
2007	55,966	45,771
2008	35,139	24,154
2009 and later	25,568	22,057

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. Questar E&P's Canadian properties were sold in the last quarter of 2002.

		Year Ended December 31,					
		Productive			Dry		
		2004	2003	2002	2004	2003	2002
Net Wells Completed							
United States	-Exploratory	4.7	3.7	0.6		0.2	1.0
	-Development	156.0	132.3	150.9	6.6	9.6	2.4
Canada	- Exploratory			0.5			
	-Development			2.3			0.4
Total	-Exploratory	4.7	3.7	1.1		0.2	1.0
	-Development	156.0	132.3	153.2	6.6	9.6	2.8
Gross Wells Completed							
United States	-Exploratory	9	10	2		2	1
	-Development	322	282	215	13	19	5
Canada	- Exploratory			1			
	-Development			9			1
Total	-Exploratory	9	10	3		2	1
	-Development	322	282	224	13	19	6

Gas Gathering and Processing

Gas Management owns 1,506 miles of gathering lines in Utah, Wyoming, Colorado and Oklahoma. 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 221 miles of gathering lines and associated field equipment.

Gas Management owns processing plants that have an aggregate capacity of 314 MMcf of unprocessed natural gas per day.

Marketing, Trading, Risk Management and Underground Gas Storage

Energy Trading, through Clear Creek Storage Company, LLC, operates an underground gas-storage reservoir in southwestern Wyoming.

ITEM 3. LEGAL PROCEEDINGS.

Market Resources is involved in a variety of pending legal disputes. Management believes that the outcome of these cases will not have a material adverse effect on financial position, operating results or liquidity. Significant cases are discussed below.

Grynberg. Questar affiliates, including Market Resources affiliates, are involved in three separate lawsuits filed by Jack Grynberg, an independent producer. The first case, *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.) involves *qui tam* claims filed by Grynberg under the federal False Claims Act and is substantially similar to the other cases filed against pipelines and their affiliates that have been consolidated for discovery and pre-trial discovery 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 Questar defendants have finished deposing Grynberg and filed a motion contending that the court has no jurisdiction over the case because Grynberg cannot satisfy the statutory requirements for jurisdiction. In other words, the Questar defendants argue that Grynberg cannot claim to be the "original source" of the information on which the allegations are based and failed to provide any information to the government before public disclosures occurred.

A special master has been handling the consolidated cases in order to expedite administrative matters. He held hearings on the motions on March 17 and 18, 2005.

The second case, *Grynberg and L & R Exploration Venture v. Questar Pipeline Co.* , Civil No. 97CV0471 (D. Wyo.) was originally stayed pending the outcome of issues raised in other cases involving the parties. This case involves some of the same allegations that were heard in an earlier case between the parties, e.g., breach of contract, intentional interference with a contract, and has additional claims of antitrust violations and fraud. In June 2001 the judge entered an order granting the motion filed by Questar defendants for partial summary judgment dismissing the antitrust claims from the case, but has not ruled on other motions for summary judgment dealing with ratable take and fraud.

The parties to the third case, *Grynberg v. Questar Pipeline Co*., No. 99090729CN (Dist. Ct. Utah), recently agreed to stay the proceedings, pending the resolution of some issues in the Wyoming case described above. The Utah case was originally filed by Grynberg against Questar Pipeline and other named Questar defendants in September of 1999. The case involves claims that Questar Pipeline mismeasured the heat content of natural gas volumes attributable to Grynberg's working interest in several wells in southwestern Wyoming and committed fraud and breached fiduciary responsibilities owed him. The trial court judge granted summary judgment to the Questar defendants and dismissed Grynberg's claims. On appeal, the Utah Supreme Court substantially upheld the trial court's decision, but ruled that Grynberg was not collaterally estopped from presenting a contract-termination issue that had been previously ruled on by a Wyoming federal district court judge in the case described above and remanded the case to the trial court to determine whether any contractual claims remain.

Kansas Cases. Energy Trading is a named defendant in tandem 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 and state lessors rather than on behalf of the federal government. The purported class involves all royalty owners of production from nonfederal and nonIndian land in Kansas, Wyoming and Colorado. Energy Trading opposes certification of the class and contends that it is not engaged in any measurement activities in Kansas. Questar affiliates engage in measurement activities, but not in Kansas.

A hearing on defendants' motion opposing class certification is scheduled to be heard on April 1, 2005.

Beaver Gas Pipeline System. On February 15, 2005, the trial court judge granted Questar E&P's motion to dismiss the lawsuit filed against it in *Kaiser-Francis Oil v. Anadarko Petroleum Corp*., Case No. CJ-2003-66518 (Dist. Ct. Okla.). This lawsuit was filed by Questar E&P's co-defendant in a prior Oklahoma case, *Bridenstine v. Kaiser-Francis Oil Co.* The original lawsuit was a class action alleging improper royalty payments for wells connected to the Beaver Gas Pipeline System in western Oklahoma. Questar E&P and Anadarko (as the successor to another company) settled the lawsuit in December 2000 by agreeing to pay a total sum of $22.5 million, of which $16.5 million was allocated to Questar E&P. Kaiser-Francis chose not to settle and was assessed damages, including punitive damages, by a jury. Kaiser-Francis ultimately settled for $82.5 million.

Kaiser-Francis' lawsuit claimed that Questar E&P and Anadarko were obligated by express and implied indemnities to pay for a portion of the damages assessed in the jury trial and for its legal-defense costs. In dismissing the lawsuit for failure to state a claim, the district judge noted that the jury determined that Kaiser-Francis was involved in a conspiracy with other working-interest owners and was barred by the doctrine of "unclean hands" from suing Questar E&P and Anadarko.

Questar E&P has settled two additional cases involving the Beaver system that were filed by the Oklahoma State Land Commission and the Oklahoma State Tax Commission.

Royalty Cases. Royalty class actions are being asserted by landowners against entities involved in the gas and oil marketing-and-production business. Questar E&P and Wexpro have been involved in several class actions and expect to be the subject of additional class-action cases involving similar claims.

Royalty payments are also audited by the Minerals Management Service, an agency within the Department of Interior, and by various states in which Questar E&P and Wexpro operate.

Environmental Matters. Questar E&P has intervened in a lawsuit that was filed by Wyoming environmental groups against the Bureau of Land Management (BLM), *Wyoming Outdoor Council v. Bennett,* Case No. 03-CV50-J (D. Wyo.) The environmental groups claim the BLM violated federal law and regulatory provisions when it approved Questar E&P's request for an exception that allowed limited drilling during the winter of 2002-03. (Questar E&P's successful efforts to extend winter drilling are described in other sections of this report.) Questar E&P contends the BLM complied with federal regulations when expanding winter drilling. Environmental groups have not appealed the latest BLM decision to grant additional access for winter drilling. A hearing on the issues was held in January 2004, but as of the date of this report the federal district court has not issued any order.

During the second quarter of 2004, the Environmental Protection Agency (EPA) issued two separate compliance orders alleging that Gas Management failed to 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 owned by Shenandoah Energy, Inc. (currently renamed QEP Uinta Basin, a subsidiary of Questar E&P) before its purchase in mid-2001. Gas Management is currently operating the facilities and filing necessary reports in compliance with regulatory requirements. It is discussing the allegations with the EPA and expects that it may be required to pay a civil penalty in excess of $100,000 in conjunction with each order.

On January 2, 2005, the Department of Environmental Quality (DEQ) for the state of Oklahoma issued a seven-count Notice of Violation to Gas Management in conjunction with the operation of the Beaver processing plant in western Oklahoma. The DEQ alleges that Gas Management violated federal and state environmental laws and regulations concerning air emissions when operating the facility and when reporting about such operations. As requested by DEQ, Gas Management filed a compliance plan by the end of February 2005. At this point, Gas Management has not been advised of any penalties but anticipates that penalties may exceed $100,000.

With the possible exceptions of an enforcement action that the EPA may bring against QEP Uinta Basin for violation of air-permit requirements for operations on tribal lands in eastern Utah and the notice issued by the Oklahoma DEQ described above, there is no pending proceeding involving formal or informal notices of violations that includes a penalty of $100,000 or more.

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 this 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.

RESULTS OF OPERATION

Market Resources operates through several subsidiaries. Questar Exploration and Production Company (Questar E&P) acquires, explores for, develops and produces gas and oil. Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas. Questar Gas Management Company (Gas Management) provides gas-gathering and processing services for affiliates and third parties. Questar Energy Trading Company (Energy Trading) markets equity and third-party gas and oil, provides risk-management services, and through Clear Creek Storage Company, LLC, operates an underground gas-storage reservoir. Following is a comparison of net income by line of business.

	Year Ended December 31,			Change	Change
	2004	2003	2002	2004 v. 2003	2003 v. 2002
Net income (loss)	(in thousands)				
Questar E&P	$ 108,158	$ 70,403	$ 56,182	$ 37,755	$ 14,221
Wexpro	35,303	32,642	30,791	2,661	1,851
Gas Management	21,047	13,333	9,119	7,714	4,214
Energy Trading and other	903	(388)	1,837	1,291	(2,225)

Total	$ 165,411	$115,990	$ 97,929	$ 49,421	$ 18,061

Market Resources Consolidated Results

Market Resources 2004 net income grew to $165.4 million versus $116.0 million in 2003, a 43% increase. Operating income increased $66.2 million, or 31%, in the year-to-year comparison from $210.3 million to $276.5 million. Total revenues increased $316.3 million, or 36%, in 2004. Revenue growth was driven by increased production, higher realized natural gas, oil and NGL prices at Questar E&P, increased throughput, higher gathering fees and improved processing margins at Gas Management, and an increased investment base in Wexpro. Revenues include sales to affiliates. Expenses increased in the 2004 period due to increased abandonment expense, exploration expense, production taxes, depreciation, depletion and amortization, and lease-operating expense.

Net income in 2003 was reduced by $5.1 million due to the cumulative effect of implementing SFAS 143, a new accounting rule governing the treatment of retirement costs of long-lived assets. Market Resources 2002 net income included a $26.8 million after-tax gain from asset sales. Following is a summary of Market Resources' financial results and operating information.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
OPERATING INCOME			
Revenues			
Natural gas sales	$ 375,220	$285,118	$205,928
Oil and natural-gas-liquids sales	86,336	67,020	67,572
Cost-of-service gas operations	116,747	100,997	93,177
Energy marketing	525,276	348,002	212,087
Gas gathering, processing and other	81,702	67,871	50,359
Total revenues	1,185,281	869,008	629,123
Operating expenses			
Energy purchases	518,437	342,476	202,132
Operating and maintenance	144,668	130,680	131,598
Depreciation, depletion and amortization	142,688	121,316	117,446
Exploration	9,239	4,498	6,086
Abandonment and impairment of gas, oil and other properties	15,758	4,151	11,183
Production and other taxes	73,243	53,343	28,558
Wexpro Agreement – oil-income sharing	4,702	2,199	1,676
Total operating expenses	908,735	658,663	498,679
Operating income	$276,546	$210,345	$130,444
OPERATING STATISTICS			
Nonregulated production volumes			
Natural gas (in MMcf)	89,801	78,811	79,674
Oil and natural gas liquids (in Mbbl)	2,281	2,324	2,764
Total production (in bcfe)	103.5	92.8	96.3
Average daily production (in MMcfe)	283	254	264
Average commodity price, net to the well			
Average realized price (including hedges)			
Natural gas (per Mcf)	$4.18	$3.62	$2.58
Oil and natural gas liquids (per bbl)	$30.97	$23.39	$20.39
Average sales price (excluding hedges)			
Natural gas (per Mcf)	$5.11	$4.17	$2.17
Oil and natural gas liquids (per bbl)	$38.10	$28.47	$22.93
Wexpro net investment base at December 31, (in millions)	$182.8	$172.8	$164.5

Natural gas-gathering volumes (in thousands of MMBtu)			
For unaffiliated customers	128,721	114,774	112,205
For Questar Gas	38,997	41,568	40,685
For other affiliated customers	56,958	46,150	38,136
Total gathering	224,676	202,492	191,026
Gathering revenue (per MMBtu)	$0.22	$0.20	$0.16
Natural gas and oil-marketing volumes (in Mdthe)	94,783	80,196	83,816

Questar E&P Results

Questar E&P 2004 net income was $108.2 million compared to $70.4 million in 2003, a 54% increase. Higher profits were driven by increased production and higher realized natural gas, oil and NGL prices. Questar E&P 2003 net income benefited from higher prices for natural gas, oil and NGL. Realized oil and NGL prices increased 15% in 2003. Realized natural gas prices increased 40% year over year compared to 2002. A change in accounting for asset-retirement obligations reduced Questar E&P income by $4.6 million in 2003.

Questar E&P production increased 12% to 103.5 bcfe in 2004 versus 92.8 bcfe in the prior year. Production growth was driven by accelerated development drilling on the Pinedale Anticline in western Wyoming and a 17% year-over-year increase from Midcontinent properties. Natural gas remains the primary focus of Questar E&P's exploration and production strategy. On an energy-equivalent ratio, natural gas comprised approximately 87% of 2004 production A comparison of gas-equivalent production by region are shown in the following table.

	Year Ended December 31,		
	2004	2003	2002
		(in bcfe)	
Rocky Mountains			
Pinedale Anticline	23.5	15.2	8.6
Uinta Basin	24.8	29.0	26.8
Rockies Legacy	18.0	16.7	20.7
Subtotal – Rocky Mountains	66.3	60.9	56.1
Midcontinent			
Tulsa	19.9	13.9	14.5
Oklahoma City	17.3	18.0	18.2
Subtotal – Midcontinent	37.2	31.9	32.7
Canada			7.5
Total production	103.5	92.8	96.3

At December 31, 2004, Market Resources operated 104 producing wells on the Pinedale Anticline compared to 76 at the end of 2003. Questar E&P's 2004 production from Pinedale was 23.5 bcfe compared to 15.2 bcfe in 2003. Production volumes from the Uinta Basin in eastern Utah decreased 15% in 2004 compared to 2003. Uinta Basin production decline has flattened significantly, with second-half 2004 production volumes essentially equal to first-half 2004. Production from Rockies legacy properties was 18.0 bcfe in 2004 compared to 16.7 bcfe in 2003, an 8% increase. Legacy properties include all of Questar E&P's Rocky Mountain producing properties except Pinedale and the Uinta Basin. Continued good performance from Questar E&P's Hartshorne coalbed-methane development project in the Arkoma Basin of eastern Oklahoma and ongoing infill-development drilling on the Elm Grove properties in northwest Louisiana drove Midcontinent results. Current-year Midcontinent production was up 5.3 bcfe, or 17%, compared to 2003.

Questar E&P benefited from higher realized prices for natural gas, oil and NGL in 2004. The weighted-average realized natural gas price for Questar E&P (including the effects of hedging) was $4.18 per Mcf in 2004 compared to $3.62 per Mcf for 2003, a 15% increase. For 2004, realized oil and NGL prices averaged $30.97 per bbl (including the effects of hedging), compared with $23.39 per bbl in 2003, a 32% increase. A comparison of average-realized prices by region, including hedges, is shown in the following table.

	Year Ended December 31,		
	2004	2003	2002
Natural gas (per Mcf)			
Rocky Mountains	$3.95	$3.27	$2.14
Midcontinent	4.57	4.26	3.35
Canada			2.22
Volume-weighted average	4.18	3.62	2.58
Oil and NGL (per bbl)			

Rocky Mountains	$30.10	$21.95	$19.72
Midcontinent	32.98	27.04	21.67
Canada			21.03
Volume-weighted average	30.97	23.39	20.39

Realized natural gas prices in Questar E&P's core Rockies areas increased significantly in 2004 compared to 2003. Approximately 63% of Questar E&P's 2004 natural gas production came from Rockies properties. Rockies basis, the regional difference between Rockies prices and the reference Henry Hub price, averaged approximately $0.90 per MMBtu for 2004 compared to $1.27 per MMBtu for 2003. The May 2003 completion of a major interstate-pipeline expansion that delivers Rockies gas to western U. S. markets alleviated the transportation bottleneck that adversely affected Rockies gas prices during much of the first half of 2003. About two-thirds of 2003 production was in the Rockies region and one-third in the Midcontinent region. Rockies gas prices increased 53% in 2003 versus 2002. In response to lower gas prices in 2002 Questar E&P shut in 3.3 bcfe of Rockies gas production. Midcontinent realized natural gas prices were 27% higher in 2003 compared with 2002.

Approximately 76% of Questar E&P's gas production in 2004 was hedged or pre-sold at an average price of $4.04 per Mcf net to the well. Net-to-the-well prices reflect adjustments for regional basis, gathering and processing costs, and gas quality. Hedging reduced gas revenues $83.9 million in 2004. Market Resources also hedged or pre-sold approximately 66% of its oil production in 2004 at an average net-to-the-well price of $30.98 per bbl. Hedging reduced oil revenues $16.3 million during 2004. Market Resources may hedge up to 100% of its forecasted production from proved developed reserves to lock in acceptable returns on invested capital and to protect cash flows and earnings from a decline in commodity prices. Market Resources has continued to take advantage of higher natural gas and oil prices to add to its hedge positions in 2005, 2006 and 2007. Natural gas and oil hedges as of December 31, 2004, are summarized in Item 7A. of this report.

Questar E&P pre-income tax cost structure is summarized in the following table.

	Year Ended December 31,		
	2004	2003	2002
		(per Mcfe)	
Lease-operating expense	$0.50	$0.49	$0.55
Production taxes	0.46	0.34	0.18
Lifting costs	0.96	0.83	0.73
Depreciation, depletion and amortization	1.02	0.96	0.92
General and administrative expense	0.30	0.29	0.27
Allocated-interest expense	0.21	0.23	0.27
Total	$2.49	$2.31	$2.19

Lifting costs were $0.13 per Mcfe higher in 2004 versus 2003 due primarily to a 35% increase in production taxes resulting from higher sales prices of natural gas, oil and NGL. Most production taxes are based on a fixed percentage of commodity-sales prices. Depreciation, depletion and amortization expense increased 6% in 2004 compared to a year ago due to higher reserve-replacement costs and ongoing_depletion of older, lower-cost successful-efforts pools. Increased competition for rigs and other services in core operating areas, along with sharply higher steel prices, has increased drilling and completion costs. General and administrative expenses increased $0.01 per Mcfe, or 3%, in 2004 versus 2003 due primarily to higher labor and employee-benefit costs and higher compliance costs. Allocated interest decreased about 9% on a unit-of-production basis to $0.21 per Mcfe versus $0.23 per Mcfe in 2003 due primarily to increased production volumes.

Lease-operating expenses were lower in the 2003 period after the 2002 sale of higher-cost Canadian and other properties. Higher sales prices in 2003 compared with 2002 resulted in higher production taxes. Depreciation, depletion and amortization rates increased in 2003 over 2002 due to higher costs and, in part, lower estimated reserves in Questar E&P's Uinta Basin properties.

In 2004 impairments totaling $5.7 million were recognized for Bovina field in Mississippi due to collapsed casing on one well, and the uneconomic coalbed-methane play at the Copper Ridge Unit in Wyoming. Dry-hole expense of $3.9 million was recorded for the unsuccessful deeper exploratory zones in a Brady Field well in western Wyoming.

Pinedale Anticline Drilling Activity

During 2004 Market Resources drilled and completed 28 wells, had four additional wells drilled to intermediate casing point and suspended until May 2005, and had three wells waiting on completion at year-end. Two of the wells waiting on completion were completed and turned to sales in January 2005. In addition, two rigs were actively drilling on the winter pad on December 31, 2004. In mid-July 2004, Market Resources commenced drilling a well to test the deep potential of its Pinedale acreage. The 19,500-foot Stewart Point 15-29 well, designed to test the potential of the Rock Springs and Blair formations beneath the Lance Pool pay zones at Pinedale, was delayed over two months due to sage grouse activity. The pace of drilling on the well was hampered by chronic mechanical problems with the contracted drilling rig and inexperienced rig crews. In November 2004, drilling operations were suspended at intermediate casing point at a depth of 14,200 feet and the rig was released. A different rig will be used to finish drilling the well to total depth when operations resume in May 2005.

Pinedale Anticline Year-Round Drilling Proposal

On April 15, 2004, Market Resources submitted a proposal to the BLM seeking a long-term exception to the winter-drilling restrictions on its Pinedale acreage from November 15 through May 1. On November 9, 2004, a BLM Decision gave Market Resources approval to phase-in over the next year the company's proposed year-round drilling program. The BLM decision allows Market Resources to operate two drilling rigs on one pad during the winter of 2004-2005. After proposed water and condensate gathering lines are completed in 2005, Market Resources will be allowed to operate six rigs from three active pads beginning in the winter of 2005-2006 through the winter of 2013-2014.

Market Resources believes that year-round drilling from pads is the most efficient and environmentally responsible approach for developing its Pinedale acreage. Market Resources' year-round drilling program will shorten the anticipated development drilling period from 18 years to about 9 years. Market Resources can drill up to 16 directional wells per single surface pad. With year-round drilling, surface disturbance will be reduced initially by about two-thirds from almost 1,500 acres currently allowed to around 500 acres. Surface disturbance would be further reduced to less than 250 acres with post-drilling reclamation.

Other benefits of Market Resources' year-round drilling program include a substantial reduction in emissions, noise, dust and traffic compared to the current situation in which activities are compressed into the summer months. Year-round drilling also creates year-round jobs and thus a more-stable, better-trained, more-productive and safer workforce in the drilling and completion-service industries.

Market Resources has committed to build pipelines to transport condensate and water production off the portion of the Pinedale Anticline where Market Resources' acreage is located. The pipelines will eliminate the need for storage tanks at each location and up to 25,500 tanker-truck trips per year at peak production. Other key components of the BLM decision are funding for continued monitoring of mule deer and other critical wildlife, monitoring air quality, and habitat enhancement on contiguous undeveloped areas of Market Resources' Pinedale leasehold.

Pinedale Anticline 20-Acre Spacing Approved

During the third quarter of 2004, the Wyoming Oil and Gas Conservation Commission issued a formal order approving 20-acre-density drilling of Lance Pool (Lance and Mesaverde Formation) wells on all of Market Resources Pinedale Anticline acreage held at the end of 2003 (approximately 14,800 acres). With 20-acre spacing Market Resources has up to 470 total well locations on its Pinedale leasehold (including several recently acquired tracts that have not yet been approved for 20-acre spacing) with approximately 359 locations remaining to be drilled at the end of 2004. Market Resources has over 17,951 gross acres under lease at Pinedale. Questar E&P and Wexpro have a combined 67% average working interest in the 470 total development locations covering approximately 9,400 productive acres in the Lance Pool (combined Lance and Mesaverde formations) at Pinedale. Of the 470 gross Lance Pool development locations on Market Resources' leasehold, Questar E&P has about 263 net locations and Wexpro has about 54.

Market Resources estimates that each 20-acre-spaced well drilled and completed in the Lance and Mesaverde Formations will recover between 3.8 and 8.8 bcfe of gross-incremental reserves. Questar E&P's average working interest in horizons beneath the productive limits of the Lance Pool is approximately 75%. Wexpro has no working interest in deeper horizons.

New Pinedale Leases

During the third quarter of 2004, Questar E&P acquired additional federal leases on 2,018 acres adjacent to the southwest side of the current 14,800-acre leasehold. Subject to approval of 20-acre spacing, this newly acquired Pinedale acreage may add up to 32 drilling locations. Questar E&P has a 100% working interest in these new leases. Several groups have appealed the issuance of these leases.

Wexpro

Wexpro net income increased 8% to $35.3 million in 2004 compared to $32.6 million in 2003. Wexpro manages, develops and produces gas reserves for affiliated company Questar Gas. Wexpro activities are governed by a long-standing agreement (Wexpro Agreement) with the states of Utah and Wyoming. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19% on its net investment in commercial wells and related facilities – known as the investment base – adjusted for working capital, deferred taxes, and depreciation. Wexpro's net investment base increased to $182.8 million at December 31, 2004, up $10 million over 2003. Wexpro's net income also benefited from higher oil and NGL prices in 2004.

Wexpro earned $32.6 million in 2003 compared to $30.8 million in 2002 due to increased investment in gas-development wells, higher realized prices for oil, capitalized interest associated with construction, and lower debt expense. Wexpro's 2003 results included a $0.5 million after-tax charge for the cumulative effect of an accounting change for asset-retirement obligations.

Gas Management

Net income from gas-gathering and processing services increased 58% to $21 million in 2004 versus $13.3 million in 2003. Gathering margins increased by $7 million due to an 11% increase in volumes and a 2.3-cent-per-MMBtu increase in gathering rates. Pinedale production and new projects serving third parties in the Uinta Basin are driving the expanded service. Gas Management gas-processing margins (revenue from the sale of natural gas liquids less natural gas purchases and operating expenses) improved by 7.6 cents per gallon due to higher NGL sales prices. To reduce processing-margin volatility, Gas Management began hedging NGL prices in 2004 using forward-sales contracts. Hedging reduced NGL revenues by $0.5 million in 2004.

Net income from gas-gathering and processing operations increased 46% to $13.3 million in 2003 compared to 2002. Gathering volumes increased 11.5 MMBtu to 202.5 MMBtu in 2003 as the result of increased investment in gathering facilities in the Pinedale area.

Pre-tax earnings from Gas Management's 50% interest in Rendezvous increased to $5 million in 2004 from $4.7 million for 2003 and $2.2 million in 2002. Rendezvous provides gas-gathering services for the Pinedale and Jonah producing areas.

Energy Trading

Net income from Energy Trading was $0.9 million in 2004 compared to a loss of $0.4 million in the year-earlier period. Gross margins for gas and oil marketing (gross revenues less the costs to purchase gas and oil, commitments to gas-transportation contracts on interstate pipelines, and gas-storage costs), increased to $6.8 million for 2004 versus $5.4 million for 2003. Current-year results were positively impacted by higher unit margins and increased sales volumes. Gross margins declined in 2003 compared with 2002 due primarily to losses from long-term transportation contracts that were above market rates for much of 2003.

Energy Trading is the sole member in Clear Creek Storage, LLC, which operates the Clear Creek natural gas-storage facility in southwestern Wyoming. Clear Creek has working-gas-storage capacity of approximately 3 bcf and is connected to four interstate pipelines – Kern River, Northwest, Overthrust and Questar Pipeline.

Consolidated Operating Results After Operating Income

Interest and Other Income

In 2002 Market Resources sold noncore properties resulting in a $43.2 million pretax gain and favorably settled a lawsuit and other contracts resulting in a $5.6 million of pretax earnings.

Earnings of Unconsolidated Affiliates

Rendezvous Gas Services income increased in 2004 due to higher gas throughput on its gathering system. Gas Management is a 50% member in Rendezvous, which provides gas-gathering services for the Pinedale-Jonah producing area of western Wyoming. Gas Management became the sole owner of the Blacks Fork processing plant in the fourth quarter of 2002 after owning a 50% interest in prior periods.

Debt Expense

Lower debt balances and long-term interest rates resulted in lower debt expense in 2004 compared with 2003. Market Resources reduced its revolving long-term debt by $55.0 million in 2004 and $145.0 million in 2003.

Income Taxes

The effective combined federal, state and foreign income tax rate was 35.5% in 2004, 36.3% in 2003 and 35.2% in 2002. The Section 29 income tax credit associated with production of nonconventional fuels expired December 31, 2002. The nonconventional-fuel credits amounted to $4.9 million in 2002.

Cumulative Effect of Changes in Accounting Methods

On January 1, 2003, the Company adopted a new accounting rule, SFAS 143, "Accounting for Asset Retirement Obligations" and recorded a cumulative effect that reduced net income by $5.1 million. SFAS 143 accretion expense amounted to $2.8 million and $2.3 million in 2004 and 2003, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Net income	$165,411	$115,990	$ 97,929
Noncash adjustments to net income	234,602	195,637	146,952
Changes in operating assets and liabilities	13,001	(53,497)	13,243
Net cash provided from operating activities	$413,014	$258,130	$258,124

Net cash provided from operating activities increased 60% in 2004 compared with 2003 due primarily to increased income, changes in operating assets and liabilities and noncash adjustments to income.

Investing Activities

In 2004 Market Resources increased drilling activity at Pinedale and in the Midcontinent region. During 2004 Market Resources participated in 413 wells (167.3 net), resulting in 160.7 net successful gas and oil wells and 6.6 net dry or abandoned wells. The net drilling-success rate was 96% in 2004. There were 67 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. Capital expenditures for 2003 and 2004 and a forecast for 2005 follow.

	Year Ended December 31,		
	2005 Forecast	2004	2003
	(in thousands)		
Drilling and other exploration	$ 17,400	$ 29,229	$ 11,055
Development drilling	220,800	222,455	146,608
Wexpro development drilling	47,800	39,184	33,028
Reserve acquisitions		1,131	2,492
Production	13,400	13,640	9,687
Gathering and processing	71,500	26,979	31,448
Storage	300	1,171	333
General	4,300	12,040	3,480
	375,500	345,829	238,131
Capital expenditure accruals		(13,023)	(11,370)
Total capital expenditures	$375,500	$332,806	$226,761

Financing Activities

Net cash flow provided from operating activities exceeded the sum of net capital expenditures and dividends by $64.9 million in 2004 and $23.1 million in 2003. The Company used surplus cash flow generated from operations plus the collection of loans to Questar to repay debt. Market Resources repaid $55 million of revolving long-term debt in 2004 and paid down its revolving debt by $145 million in 2003.

Short-term borrowings amounted to $61.2 million at December 31, 2004, compared with $36.5 million a year earlier. The weighted-average interest rate on short-term debt balances at December 31 was 2.42% in 2004 and 1.30% in 2003.

Market Resources consolidated capital structure consisted of 34% combined short- and long-term debt and 66% common shareholder's equity at December 31, 2004. A year earlier debt represented 40% and shareholder's equity 60% of capitalization. Moody's and Standard & Poor's have rated Market Resources senior unsecured debt Baa3 and BBB+, respectively. Moody's ratings are designated as stable while the Standard & Poor's ratings carry a negative outlook qualifier.

The fair value of hedging contracts at December 31, 2004, caused current liabilities to exceed current assets.

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, 2004.

	Payments Due by Year				
	Total	2005	2006-2007	2008-2009	After 2009
			(in millions)		
Long-term debt	$350.0		$200.0		$150.0
Transportation and storage contracts	58.7	$7.2	13.6	$11.4	26.5
Operating leases	6.0	2.3	3.5	.2	
Total	$414.7	$9.5	$217.1	$11.6	$176.5

Critical Accounting Policies, Estimates and Assumptions

Market Resources' significant accounting policies are described in Note 1 accompanying the consolidated financial statements included in Item 8. of this 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.

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. If the undiscounted pretax cash flows are less than the net book value of the asset group, the asset value is written down to estimated fair value which is determined using discounted future net revenues.

Accounting for Derivatives

The Company uses derivative instruments, typically fixed-price swaps, to hedge against a decline in the realized prices of its gas and oil production. Accounting rules for derivatives require that these instruments be marked 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 revenues are presented on a gross-revenue basis.

Recent Accounting Developments

Refer to Note 1 accompanying the consolidated financial statements in Item 8. 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, estimation of gas and oil reserves 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-hedging 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. Hedging contracts are used for a significant share of Questar E&P-owned gas and oil production and for a portion of gas- and oil-marketing transactions and for 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 supports 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 Board of Directors. Market Resources may hedge up to 100% of forecast nonregulated production from proved-developed reserves when prices meet earnings and cash-flow objectives. Proved-developed production represents production from existing wells. Market Resources does not enter into derivative arrangements for speculative purposes and does not hedge undeveloped reserves or equity NGL.

Hedges 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. Gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Any ineffective portion of hedges is immediately recognized in the income statement. The ineffective portion of hedges was not significant in 2004 and 2003.

As of December 31, 2004, approximately 74.3 bcf of forecast full-year 2005 gas production was hedged at an average price of $4.90 per Mcf, net to the well.

Market Resources enters into commodity-price-hedging arrangements with several banks and energy-trading firms. Generally the contracts allow some amount of credit before Market Resources is required to deposit collateral for out-of-the-money hedges. In some contracts the amount of credit varies depending on the credit rating assigned to Market Resources' debt. Market Resources' current ratings support individual counterparty lines of credit of $5 million to $40 million. If Market Resources credit ratings fall below investment grade (BBB- by Standard & Poor's or Baa3 by Moody's), counterparty credit generally falls to zero. In addition to the counterparty arrangements, Market Resources has a $200 million revolving-credit facility in place with banks.

A summary of Market Resources hedging positions for equity production as of December 31, 2004, is shown below. Prices are net to the well. Currently all hedges are fixed-price swaps with creditworthy counterparties, allowing Market Resources to achieve a known price for a specific volume of production delivered into a regional sales point. The swap price is then reduced by gathering costs and adjusted for product quality to determine the net-to-the-well price.

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Time periods	Rocky Mountains	Midcontinent	Total	Rocky Mountains	Midcontinent	Total
		Gas (in bcf)		Average price per Mcf, net to the well		
First half of 2005	24.0	13.7	37.7	$4.73	$5.33	$4.95
Second half of 2005	23.6	13.0	36.6	4.65	5.23	4.86
12 months of 2005	47.6	26.7	74.3	4.69	5.28	4.90
First half of 2006	12.2	3.4	15.6	$4.96	$5.55	$5.09
Second half of 2006	12.4	3.5	15.9	4.96	5.55	5.09
12 months of 2006	24.6	6.9	31.5	4.96	5.55	5.09
First half of 2007	1.7		1.7	$5.08		$5.08
Second half of 2007	1.7		1.7	5.08		5.08
12 months 2007	3.4		3.4	5.08		5.08
		Oil (in Mbbl)		Average price per bbl, net to the well		
First half of 2005	362	181	543	$33.41	$34.70	$33.84
Second half of 2005	368	184	552	33.41	34.70	33.84

12 months of 2005	730	365	1,095	33.41	34.70	33.84

Market Resources held gas-price hedging contracts covering the price exposure for about 135.6 MMdth of gas, 1.1 MMbbl of oil and 3.8 MMgal of NGL as of December 31, 2004. A year earlier Market Resources' hedging contracts covered 148.1 MMdth of natural gas. Market Resources may hedge NGL prices in its processing business.

The following table summarizes changes in the fair value of hedging contracts from December 31, 2003, to December 31, 2004.

	(in thousands)
Net fair value of gas- and oil-hedging contracts outstanding at December 31, 2003	($49,098)
Contracts realized or otherwise settled	49,074
Increase in gas and oil prices on futures markets	(51,668)
Contracts added	(15,809)
Net fair value of gas- and oil-hedging contracts outstanding at December 31, 2004	($67,501)

A table of the net fair value of gas-hedging contracts as of December 31, 2004, is shown below. About 81% of the fair value of all contracts will settle and be reclassified from other comprehensive income in the next 12 months.

	(in thousands)
Contracts maturing by December 31, 2005	($54,845)
Contracts maturing between December 31, 2005, and December 31, 2006	(12,276)
Contracts maturing between December 31, 2006, and December 31, 2007	(380)
Net fair value of gas- and oil-hedging contracts at December 31, 2004	($67,501)

The following table shows sensitivity of the mark-to-market valuation of gas and oil price-hedging contracts to changes in the market price of gas and oil.

	At December 31,	
	2004	2003
	(in millions)	
Mark-to-market valuation – asset (liability)	($67.5)	($49.1)
Value if market prices of gas and oil decline by 10%	2.5	1.3
Value if market prices of gas and oil increase by 10%	(137.5)	(99.5)

Interest-Rate Risk Management

Market Resources had $350 million of fixed-rate debt with a fair value of $385.3 million and $395.5 million at December 31, 2004 and 2003, respectively. The fair value of fixed-rate debt is subject to change as interest rates fluctuate. The Company held variable-rate long-term debt at December 31, 2003 amounting to $55 million. The book value of variable-rate debt approximates fair value.

Credit Risk

Market Resources requests credit support and, in some cases, prepayment from companies with unacceptable credit risks. Market Resources' five largest customers are BP Energy, Sempra Energy Trading, Coral Energy Resources LP, ONEOK Energy Marketing and Virginia Power Energy. Sales to these companies accounted for 33% of Market Resources revenues in 2004 and their accounts were current at December 31, 2004.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Financial Statements: Page No.

Financial Statement Schedules:

For the three years ended December 31, 2004

Valuation and Qualifying Accounts

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

Board of Directors
Questar Market Resources, Inc.

We have audited the accompanying consolidated balance sheets of Questar Market Resources, Inc. and subsidiaries as of December 31, 2004 and 2003, 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, 2004. 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Questar Market Resources, Inc. and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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 Notes 1 and 2 to the financial statements, Questar Market Resources, Inc. and subsidiaries adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," effective January 1, 2002 and Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003.

/s/ Ernst & Young LLP
Ernst & Young LLP

Salt Lake City, Utah
March 3, 2005

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
REVENUES			
From unaffiliated customers	$1,053,854	$751,502	$522,476
From affiliates	131,427	117,506	106,647
TOTAL REVENUES	1,185,281	869,008	629,123
OPERATING EXPENSES			
Cost of natural gas and other products sold	518,437	342,476	202,132
Operating and maintenance	144,668	130,680	131,598
Depreciation, depletion and amortization	142,688	121,316	117,446
Exploration	9,239	4,498	6,086
Abandonment and impairment of gas,			

oil and other properties	15,758	4,151	11,183
Production and other taxes	73,243	53,343	28,558
Wexpro Agreement-oil income sharing	4,702	2,199	1,676
TOTAL OPERATING EXPENSES	908,735	658,663	498,679
OPERATING INCOME	276,546	210,345	130,444
Interest and other income	2,510	2,851	50,894
Earnings from unconsolidated affiliates	5,125	5,008	3,977
Minority interest	(270)	183	484
Debt expense	(27,412)	(28,158)	(34,705)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT	256,499	190,229	151,094
Income taxes	91,088	69,126	53,165
INCOME BEFORE CUMULATIVE EFFECT	165,411	121,103	97,929
Cumulative effect of accounting change for asset retirement obligations, net of income taxes of $3,049		(5,113)	
NET INCOME	$ 165,411	$115,990	$ 97,929

See notes accompanying consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2004	2003
	(in thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents		$ 3,716
Notes receivable from Questar	$ 49,400	6,900
Accounts receivable, net	174,539	131,889
Accounts receivable from affiliates	19,247	16,981
Hedging collateral deposits		9,100
Fair value of hedging contracts	9,334	2,283
Inventories, at lower of average cost or market		
Gas and oil storage	22,604	17,179
Material and supplies	8,631	3,769
Prepaid expenses and other	16,632	9,394
TOTAL CURRENT ASSETS	300,387	201,211
PROPERTY, PLANT AND EQUIPMENT – successful efforts method of accounting for gas and oil properties		
Gas and oil properties		
Proved properties	1,602,143	1,315,330
Unproved properties, not being depleted	62,678	95,208
Support equipment and facilities	16,932	22,569
Cost-of-service gas and oil properties	516,162	472,983
Gathering, processing, marketing and other	258,417	243,081
	2,456,332	2,149,171

Less accumulated depreciation, depletion and amortization		
Gas and oil properties	600,366	501,825
Cost-of-service gas and oil properties	262,523	239,035
Gathering, processing, marketing and other	74,378	75,985
	937,267	816,845
NET PROPERTY, PLANT AND EQUIPMENT	1,519,065	1,332,326
INVESTMENT IN UNCONSOLIDATED AFFILIATES	33,229	36,393
OTHER ASSETS		
Goodwill	61,423	61,423
Contract receivable from Questar Gas	5,097	8,256
Fair value of hedging contracts	1,815	1,578
Other noncurrent assets	7,782	4,774
	76,117	76,031
	$1,928,798	$1,645,961

LIABILITIES AND SHAREHOLDER'S EQUITY

	December 31, 2004	2003
	(in thousands)	
CURRENT LIABILITIES		
Checks in excess of cash balance	$ 4,394	
Notes payable to Questar	61,200	$ 36,500
Accounts payable and accrued expenses		
Accounts and other payables	176,974	110,865
Accounts payable to affiliates	6,372	3,957
Production and other taxes	36,127	31,361
Interest	8,495	8,549
Federal income taxes	4,559	2,247
Total accounts payable and accrued expenses	232,527	156,979
Fair value of hedging contracts	64,179	51,137
Current portion of long-term debt		55,000
TOTAL CURRENT LIABILITIES	362,300	299,616
LONG-TERM DEBT, less current portion	350,000	350,000
DEFERRED INCOME TAXES	313,511	250,546
ASSET-RETIREMENT OBLIGATIONS	66,375	60,493
FAIR VALUE OF HEDGING CONTRACTS	14,471	1,822
OTHER LONG-TERM LIABILITIES	33,271	25,346
MINORITY INTEREST		7,864
COMMITMENTS AND CONTINGENCIES – Note 7		
SHAREHOLDER'S EQUITY		
Common stock - par value $1 per share; authorized, 25,000,000 shares; issued and outstanding, 4,309,427 shares	4,309	4,309
Additional paid-in capital	116,027	116,027
Retained earnings	710,684	562,573
Accumulated other comprehensive loss	(42,150)	(32,635)

TOTAL SHAREHOLDER'S EQUITY	788,870	650,274
	$1,928,798	$1,645,961

See notes accompanying consolidated financial statements

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

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Comprehensive Income (Loss)
			(in thousands)		
Balance at January 1, 2002	$4,309	$116,027	$383,254	$22,839	
2002 net income			97,929		$ 97,929
Dividends paid			(17,300)		
Other comprehensive income					
Change in unrealized loss on energy hedges, net income taxes of $25,651				(42,799)	(42,799)
Change in interest-rate swaps, net of income taxes of $235				392	392
Foreign currency translation adjustment, net income taxes of $2,375				2,688	2,688
Balance at December 31, 2002	4,309	116,027	463,883	(16,880)	$ 58,210
2003 net income			115,990		$115,990
Dividends paid			(17,300)		
Other comprehensive income					
Change in unrealized loss on energy hedges, net income taxes of $9,429				(15,755)	(15,755)
Balance at December 31, 2003	4,309	116,027	562,573	(32,635)	$100,235
2004 net income			165,411		$165,411
Dividends paid			(17,300)		
Other comprehensive income					
Change in unrealized loss on energy hedges, net income taxes of $5,677				(9,515)	(9,515)
Balance at December 31, 2004	$4,309	$116,027	$710,684	($42,150)	$155,896

See notes accompanying consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2004	2003	2002
		(in thousands)	
OPERATING ACTIVITIES			
Net income	$ 165,411	$ 115,990	$ 97,929

Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation, depletion and amortization	147,068	125,673	122,657
Deferred income taxes	68,641	58,839	53,684
Abandonment and impairment of gas, oil and other properties	15,758	4,151	11,183
Earnings from unconsolidated affiliates, net of cash distributions	3,164	1,974	3,241
Net (gain) loss from asset sales	(315)	14	(43,240)
Cumulative effect of accounting change		5,113	
Minority interest and other	286	(127)	(573)
Changes in operating assets and liabilities:			
Accounts receivable and qualifying hedging collateral	(35,838)	(51,483)	(22,498)
Inventories	(10,287)	(9,807)	8,339
Prepaid expenses and other	(7,216)	(1,429)	2,187
Accounts payable and accrued expenses	58,802	16,851	(379)
Federal income taxes	2,312	(12,068)	22,771
Other assets	(3,796)	(580)	(755)
Other liabilities	9,024	5,019	3,578
NET CASH PROVIDED FROM OPERATING ACTIVITIES	413,014	258,130	258,124
INVESTING ACTIVITIES			
Capital expenditures			
Purchase of property, plant and equipment	(331,806)	(212,011)	(168,105)
Other investments	(1,000)	(14,750)	(17,885)
	(332,806)	(226,761)	(185,990)
Proceeds from disposition of property, plant equipment and other assets	2,037	9,053	157,979
NET CASH USED IN INVESTING ACTIVITIES	(330,769)	(217,708)	(28,011)
FINANCING ACTIVITIES			
Checks in excess of cash balances	4,394		
Change in notes receivable from Questar	(42,500)	88,700	(86,100)
Change in notes payable to Questar	24,700	26,600	(265,200)
Long-term debt issued			325,000
Long-term debt repaid	(55,000)	(145,000)	(179,104)
Other financing	(255)	(110)	723
Dividends paid	(17,300)	(17,300)	(17,300)
NET CASH USED IN FINANCING ACTIVITIES	(85,961)	(47,110)	(221,981)
Foreign currency translation adjustments			2
Change in cash and cash equivalents	(3,716)	(6,688)	8,134
Beginning cash and cash equivalents	3,716	10,404	2,270
Ending cash and cash equivalents	$ -	$ 3,716	$ 10,404

See notes accompanying consolidated financial statements

QUESTAR MARKET RESOURCES, INC.
NOTES ACCOMPANYING CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Summary of Significant Accounting Policies

Nature of Business

Market Resources' is a wholly owned subsidiary of Questar. Market Resources' subsidiaries acquire, explore for, develop and produce gas and oil. They also manage, develop and produce cost-of-service reserves for affiliated company, Questar Gas. They provide gas gathering and processing services for affiliates and third parties, market equity and third-party gas and oil, provide risk-management services, and own and operate an underground gas-storage reservoir.

Principles of Consolidation

The consolidated financial statements contain the accounts of Market Resources and subsidiaries. The consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and with the instructions of 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 investments in affiliates where it does not have control. Generally, the Company's investment in these affiliates equals the underlying equity in net assets.

Use of Estimates

The preparation of consolidated financial statements and notes in conformity with GAAP requires management to make 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 recognizes revenues in the period that services are provided or products are delivered. Revenues reflect the impact of price-hedging instruments. Revenues are accounted for using the sales method, whereby revenue is recognized on all gas and oil sold to purchasers. A liability is recorded to the extent that the Company has sold volumes in excess of its share of remaining reserves in an underlying property. The Company's imbalance obligations at December 31, 2004 and 2003, were $3.0 million and $2.4 million, respectively. Energy Trading revenues are recognized on a gross basis.

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 10 in Item 8. of this report 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.

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 is 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, and purchasing related support equipment and facilities are capitalized under the successful-efforts method. The costs of unsuccessful exploratory wells are charged to expense when it is determined that such wells have not located proved reserves. Costs of geological and geophysical studies and other exploratory activities are expensed as incurred. Costs associated with 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 amortization rate would be significantly affected.

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.

Cost-of-service gas and oil properties

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 10 in Item 8. of this report for more information on the Wexpro Agreement. 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 using the unit-of-production method based on proved reserves on a field basis. All other capitalized costs associated with gas and oil properties are depreciated using the unit-of-production method based on proved-developed reserves on a field basis. The Company capitalizes an estimate of the fair value of future abandonment costs, less estimated future salvage values, and depreciates those costs over the life of the related asset.

Average depreciation, depletion and amortization rates used in the 12 months ended December 31, were as follows.

	2004	2003	2002
Gas and oil properties, per Mcfe			
United States	$1.02	$0.96	$0.91
Canada (in U.S. dollars)	-	-	0.98
Combined U.S. and Canada	1.02	0.96	0.92
Cost-of-service gas and oil properties, per Mcfe	0.69	0.65	0.64

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 its 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, and/or an other-than-temporary decline in gas and oil prices. 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

The Company adopted SFAS 142, "Goodwill and Other Intangible Assets," as of January 1, 2002, and performed an initial test that indicated no impairment. Intangible assets consist primarily of goodwill acquired through business combinations. Goodwill represents the excess of the cost over the fair value of net assets of acquired businesses. Goodwill is not amortized, but is tested for impairment at a minimum of once a year or when a triggering event occurs. Annual impairment tests are conducted in the fourth quarter. If a triggering event occurs, the undiscounted net cash flows of the 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. As of December 31, 2004, the Company held about $2.0 million of intangible assets with indefinite lives, primarily storage facilities, and $1.2 million of intangible assets subject to amortization.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

The Company capitalizes interest costs when applicable. Under provisions of the Wexpro Agreement, the company capitalizes 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 $0.2 million in 2004, $1.1 million in 2003 and $0.4 million in 2002 and is included in Interest and Other Income in the Consolidated Statements of Income.

Hedging Instruments

The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value, cash flows or foreign currencies. 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 earnings in the current period.

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.

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 of the United States 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 Company 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 \$0.4 million and \$1.2 million for the years ended December 31, 2003 and 2002, respectively. In 2004 there was no bad-debt expense recorded and the allowance was reduced. The allowance for bad-debt expenses was \$2.8 million and \$4.1 million at December 31, 2004 and 2003, 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.

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 February 2005, the Financial Accounting Standards Board (FASB) Staff posted its proposed FSP FAS 19-a, "Accounting for Suspended Well Costs." At issue is the current requirement of SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," to capitalize the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The capitalized costs become part of the entity's wells, equipment, and facilities if the well successfully located proved reserves. However, if the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value. Questions have arisen as to whether there are circumstances that would permit the continued capitalization of exploratory-well costs beyond the one-year limit specified in SFAS 19 other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In its proposal, the FASB Staff states that exploratory well costs could be capitalized beyond a one-year limit if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making progress assessing reserves and the economic and operational viability of the project. Comments on the proposed FASB Staff position were due March 7, 2005. The Company drills exploratory wells in the onshore United States in petroleum-producing regions with good access to downstream markets. Factors such as weather, seasonal access restrictions on federal land, or delays caused by permitting production facilities can cause minor delays in connecting successful exploratory wells to downstream markets, but those delays are typically less than one year. The Company currently has no completed exploratory wells classified as suspended.

In December 2004, the FASB issued SFAS 153 "Exchanges of Nonmonetary Assets, an amendment of APBO 29" to address the accounting for nonmonetary exchanges of productive assets. SFAS 153 amends APBO 29, "Accounting for Nonmonetary Exchanges," which established a narrow exception from fair-value measurement for nonmonetary exchanges of similar productive assets. SFAS 153 eliminates that exception and replaces it with an exception for exchanges that do not have commercial substance. Under SFAS 153 nonmonetary exchanges are required to be accounted for at fair value, recognizing any gains or losses, if their fair value is determinable within reasonable limits and the transaction has commercial substance. SFAS 153 specifies that a nonmonetary exchange has commercial substance if future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of SFAS 153 apply to nonmonetary asset exchanges in fiscal periods beginning after June 15, 2005. Adoption of SFAS 153 is not expected to have a material impact on Market Resources financial position or results of operations.

Reclassifications

Certain reclassifications were made to prior-year consolidated financial statements to conform with the 2004 presentation of fair value hedging contracts, other long-term liabilities and capital expenditure accruals.

Note 2 – Asset-Retirement Obligations (ARO)

On January 1, 2003, Market Resources adopted 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 is estimated and depreciated over the life of the related assets. ARO are adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate.

Changes in asset-retirement obligations for the 12 months ended December 31, were as follows.

	2004	2003
	(in thousands)	
Balance at January 1,	$60,493	$55,674
Accretion	2,820	3,621
Additions	3,159	2,268
Revisions	695	
Retirements and properties sold	(792)	(1,070)
Balance at December 31,	$66,375	$60,493

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 PSCW. Pursuant to the stipulation, Wexpro collects and deposits in trust certain funds related to estimated ARO costs. The funds are used to satisfy retirement obligations as the properties are abandoned. At December 31, 2004, approximately $2.9 million was held in this trust invested in a short-term bond index fund.

Excluding the cumulative effect of implementation, the pro forma net-income effect of the retroactive application of SFAS 143 as of January 1, 2002, would not have been material. The pro forma ARO as of January 1, 2002, was $52.4 million.

Note 3 – Investment in Unconsolidated Affiliates

Market Resources, indirectly through subsidiaries, has interests in businesses accounted for on the equity basis. As of December 31, 2004, and 2003, these affiliates did not have debt obligations with third-party lenders. The principal business activities, form of organization and percentage ownership are listed below. Percentage of voting control and economic interest are identical. Canyon Creek Compression Co., a general partnership (15%), and Rendezvous Gas Services, LLC (50%), are engaged in gathering and compressing natural gas. The remaining 50% interest in the Blacks Fork Gas Processing Co. was acquired in 2002.

Summarized results representing 100% interest are listed below.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Revenues	$16,857	$15,916	$25,490
Operating income	10,280	9,775	8,805
Income before income taxes	10,312	9,807	8,869
Current assets	$ 6,626	$ 5,167	$11,806
Noncurrent assets	66,010	74,111	45,704
Current liabilities	1,338	909	5,178
Noncurrent liabilities	1,073	1,589	2,182

Note 4 – Debt

Questar makes loans to Market Resources under a short-term borrowing arrangement. Short-term notes payable to Questar amounted to $61.2 million with an interest rate of 2.42 % and $36.5 million with an interest rate of 1.30% at December 31, 2004 and 2003, respectively.

The details of long-term debt at December 31 are listed below. All notes and the revolving-credit loan are unsecured obligations and rank equally with all other unsecured liabilities. At December 31, 2004, Market Resources could pay a dividend of $334 million to the parent company without violating the terms of its debt covenants.

	December 31, 2004	December 31, 2003
	(in thousands)	
7% notes due 2007	$200,000	$200,000
7 ½% notes due 2011	150,000	150,000
Revolving-credit loan		55,000
Total long-term debt outstanding	350,000	405,000
Less current portion		(55,000)
	$350,000	$350,000

Maturities of long-term debt for the five years following December 31, 2004, amount to a $200 million repayment due in 2007.

Cash paid for interest was $26.9 million in 2004, $28.5 million in 2003 and $30.0 million in 2002.

On March 19, 2004, Market Resources completed a $200 million credit facility with a consortium of banks that replaced an existing facility that would have expired in April 2004. The facility allows for floating-rate interest and revolving loans of various maturities until March 2009. Key financial covenants place limits on minimum levels of cash flow compared to interest expense and maximum amounts of debt as a percentage of total capital. The interest rate credit spread on borrowings varies with changes in Market Resources' credit rating, but a reduction in or loss of credit ratings does not trigger an event of default under the facility.

Note 5 – Financial Instruments and Risk Management

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

	December 31, 2004		December 31, 2003	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	(in thousands)			
Financial assets				
Cash and cash equivalents	$ -	$ -	$ 3,716	$ 3,716
Notes receivable from Questar			6,900	6,900
Gas and oil price-hedging contracts	11,149	11,149	3,861	3,861
Financial liabilities				
Checks in excess of cash balance	$ 4,394	$ 4,394	$ -	$ -
Notes payable to Questar	61,200	61,200	36,500	36,500
Long-term debt	350,000	385,266	405,000	450,480
Gas and oil price-hedging contracts	78,650	78,650	52,959	52,959

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.

Gas and oil price-hedging contracts – fair value of the contracts is based on market prices as posted on the NYMEX from the last trading day of the year. The average price of the gas contracts at December 31, 2004, was $5.04 per MMBtu, representing the average of contracts with different terms including fixed, various "into-the-pipe" postings and NYMEX references. Price-hedging contracts were in place for equity-gas production and gas-marketing transactions. Gas hedges are structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Deducting transportation and heat-value adjustments on the hedges of equity gas as of December 31, 2004, would result in an average price of $4.96 per Mcf, net to the well. The average price for oil contracts at December 31, 2004, was $35.32 per bbl. Oil contracts related to equity production would result in a net-to-the-well price of $33.84 per bbl.

Market Resources held gas-price-hedging contracts covering the price exposure for about 135.6 MMdth of natural gas 1.1

MMbbl of oil and 3.8 MMgal of NGL as of December 31, 2004. Gas Management, a subsidiary of Market Resources, uses forward-sales contracts to secure the price received for NGL processed from its plants. About 81% of those contracts will settle and be reclassified from other comprehensive income in 2005. A year earlier Market Resources hedging contracts covered 148.1 million dth of natural gas.

At December 31, 2004, the Company reported a liability, net of hedging assets, of $67.5 million from hedging activities. Settlement or realizations of contracts in 2004 resulted in a reduction of revenue of $49.1 million. The offset to the hedging liability, net of income taxes, was a $9.5 million unrealized loss on hedging activities recorded in other comprehensive loss in the shareholder's equity section of the balance sheet. Settlement of contracts resulted in reclassifying $15.8 million from comprehensive loss in 2003 and $42.4 million from comprehensive income in 2002 to the income statement. The ineffective portion of hedging transactions recognized in earnings was not significant. The fair-value calculation of gas- and oil-price hedges 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 6 – 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,		
	2004	2003	2002
	(in thousands)		
Federal			
Current	$24,015	$11,040	($1,742)
Deferred	59,539	55,176	39,839
State			
Current	(1,569)	(753)	(2,902)
Deferred	9,103	3,663	12,302
Foreign			5,668
	$91,088	$69,126	$53,165

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,		
	2004	2003	2002
	Percentages		
Statutory federal income tax rate	35.0	35.0	35.0
State income taxes, net of federal income tax benefit	1.9	1.0	4.0
Nonconventional fuel credits			(3.3)
Percentage depletion	(0.4)		
Foreign income taxes			(0.1)
Goodwill			1.0
Other	(1.0)	0.3	(1.4)
Effective income tax rate	35.5	36.3	35.2

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

	December 31,	
	2004	2003
	(in thousands)	
Deferred-tax liabilities:		
Property, plant and equipment	$356,869	$290,697
Deferred-tax assets:		
Mark-to-market and hedging activities	25,335	18,361
Alternative minimum tax credit carried forward	13,969	13,898
Net operating loss carried forward		1,091

Employee benefits and compensation costs	4,054	6,801
	43,358	40,151
Net deferred income taxes	$313,511	$250,546

Cash paid for income taxes was $22.6 million and $23.7 million in 2004 and 2003, respectively. The Company received $32.0 million of refunded income taxes in 2002 resulting primarily from timing differences caused by intangible-drilling costs. Alternative minimum tax credits do not have an expiration date.

Note 7 – Commitments and Contingencies

There are various legal proceedings against the Company and its affiliates. Management believes that the outcome of these cases will not have a material effect on the Company's financial position, operating results or liquidity.

Commitments

Subsidiaries of Market Resources have contracted for firm-transportation and storage services with various 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)
2005	$ 7.2
2006	6.8
2007	6.8
2008	6.1
2009	5.3
2010 through 2018	$26.5

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. Other leases expire in 2008. The minimum future payments under the terms of long-term operating leases for the Company's primary office locations for the four years following December 31, 2004 are as follows.

	(in millions)
2005	$2.3
2006	2.0
2007	1.5
2008	0.2

Total rental expense amounted to $2.2 million in 2004, $2.1 million in 2003 and $2.4 million in 2002. Sublease-rental receipts were $20,000 in 2004, $111,000 in 2003 and $70,000 in 2002.

Note 8 – Employee Benefits

Pension Plan

Most 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 retirement plan approximately equal to the yearly expense. 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 $2.3 million in 2004, $1.6 million in 2003 and $0.9 million in 2002.

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, 2004 and 2003, Questar's accumulated 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. The Company is amortizing its transition obligation over a 20-year period, which began in 1992. A third-party consultant calculates the projected benefit obligation. The cost of postretirement benefits other than pensions was $1.4 million in 2004, $1.4 million in 2003 and $1.3 million in 2002.

The Company's portion of plan assets and benefit obligations related to postretirement 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, 2004 and 2003, Questar's accumulated benefit obligation exceeded the fair value of plan assets.

Postemployment Benefits

Eligible Market Resources employees participate in Questar's long-term disability plan. The Company recognizes the net present value of the liability for postemployment benefits, such as long-term disability benefits and health-care and life-insurance costs, when employees become eligible for such benefits. Postemployment benefits are paid to former employees after employment has been terminated but before retirement benefits are paid. The Company accrues both current and future costs. Market Resources' postemployment liability at December 31 was $0.6 million at December 31, 2004 and 2003.

Employee Investment Plan

Market Resources' subsidiaries participate in Questar's Employee Investment Plan, which allows eligible employees to purchase shares of Questar common stock or other investments through payroll deduction. Market Resources' subsidiaries match 80% of employees' pretax purchases up to a maximum of 6% of their qualifying earnings. In addition, each year Market Resources' subsidiaries make a nonmatching contribution of $200 to each eligible employee. The Company's expense equals its matching contribution. The Company's expense amounted to $1.8 million, $1.5 million and $1.4 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Note 9 - Related Party Transactions

Market Resources receives a significant portion of its revenues from services provided to Questar Gas. The Company received $131.4 million in 2004, $117.5 million in 2003 and $106.6 million in 2002 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 10).

Market Resources pays Questar for certain administrative services. These payments were $10.1 million in 2004, $8.3 million in 2003 and $9.1 million in 2002 and were included in operating and maintenance 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 Questar Pipeline and paid $2.2 million in 2004, $2.5 million in 2003 and $1.3 million in 2002 for these services. Energy Trading markets liquids extracted from Questar Pipeline's transmission lines and paid $5.9 million in 2004 and $3.4 million to purchase the liquids in 2003. Questar InfoComm is an affiliated company that provides some information technology and communication services to Market Resources. Market Resources paid Questar InfoComm $0.8 million in 2004, $1.3 million in 2003 and $1.4 million in 2002.

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 $0.8 million in 2004 and 2003 and $0.9 million in 2002.

The Company received interest income from affiliated companies of $0.2 million in 2004, $0.9 million in 2003 and $0.7 million in 2002. Market Resources incurred debt expense to affiliated companies of $0.9 million in 2004, $0.8 million in 2003 and $2.8 million in 2002.

Note 10 – 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 share in the results of 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 continues to hold and operate all oil-producing properties previously transferred from Questar Gas's nonutility accounts. The oil production 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. The after-tax rate of return is adjusted annually and is approximately 13.2%. 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%.

b. 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 18.2%. 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%.

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

d. Wexpro conducts gas-development drilling on productive gas properties and bears any costs of dry holes. Natural gas produced from successful drilling is owned by Questar Gas. Wexpro is reimbursed for the costs of producing the gas plus a return on its investment in successful wells. The after-tax return allowed Wexpro is approximately 21.2%.

e. Wexpro operates natural-gas properties owned by 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 approximately 13.2%.

Wexpro's investment base, net of depreciation and deferred income taxes, and the yearly average rate of return for 2004 and the previous two years are shown in the table below.

	2004	2003	2002
Wexpro's net investment base (in millions)	$182.8	$172.8	$164.5
Annual average rate of return (after tax)	19.7%	19.8%	20.5%

Note 11 – Dispositions and Acquisitions

Sale of Canadian Properties

In October 2002 Market Resources sold its Canadian exploration and production subsidiary and recorded a pretax gain of $19.7 million. Total consideration received was $101.6 million.

Partnership Interest Acquired

Market Resources acquired the remaining 50% interest in the Blacks Fork processing plant effective December 18, 2002.

Note 12 – Operations by Line of Business

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 including differences in the nature of products, services and regulation. Following is a summary of operations by line of business for the Year Ended December 31.

	Market Resources	Intercompany Transactions	Questar E&P	Wexpro	Gas Management	Energy Trading and other
			(in thousands)			
2004						
Revenues						
From unaffiliated customers	$1,053,854		$ 448,706	$ 17,315	$ 68,643	$ 519,190
From affiliated companies	131,427	($422,200)	90	115,637	30,300	407,600
	1,185,281	(422,200)	448,796	132,952	98,943	926,790
Operating expenses						
Cost of natural gas and other products sold	518,437	(403,385)	2,232		909	918,681
Operating expenses	144,668	(18,815)	82,501	20,449	56,719	3,814
Depreciation, depletion and amortization	142,688		107,452	25,031	9,446	759
Exploration	9,239		9,239			
Abandonment and impairment of gas, oil and other properties	15,758		12,968	2,790		
Production and other taxes	73,243		47,102	24,847	1,082	212
Wexpro Agreement - oil income sharing	4,702			4,702		
Total operating expenses	908,735	(422,200)	261,494	77,819	68,156	923,466
Operating income	276,546		187,302	55,133	30,787	3,324
Interest and other income	2,510	(25,411)	988	503	318	26,112
Earnings from unconsolidated affiliates	5,125		172		4,953	
Minority interest	(270)					(270)

Debt expense	(27,412)	25,411	(21,679)	(931)	(2,766)	(27,447)
Income taxes	(91,088)		(58,625)	(19,402)	(12,245)	(816)
Net income	$ 165,411		$ 108,158	$35,303	$21,047	$903
Identifiable assets	$1,928,798		$1,212,793	$288,644	$218,271	$209,090
Investment in unconsolidated affiliates	33,229		128		32,639	462
Capital expenditures	332,806		259,865	38,921	26,308	7,712
2003						
Revenues						
From unaffiliated customers	$ 751,502		$ 343,804	$ 13,004	$ 55,114	$339,580
From affiliated companies	117,506	($318,121)	90	101,598	25,802	308,137
	869,008	(318,121)	343,894	114,602	80,916	647,717
Operating expenses						
Cost of natural gas and other products sold	342,476	(302,929)	2,593		874	641,938
Operating expenses	130,680	(15,192)	72,008	18,786	50,847	4,231
Depreciation, depletion and amortization	121,316		90,753	20,352	9,272	939
Exploration	4,498		4,498			
Abandonment and impairment of gas, oil and other properties	4,151		4,151			
Production and other taxes	53,343		31,946	20,479	867	51
Wexpro Agreement - oil income sharing	2,199			2,199		
Total operating expenses	658,663	(318,121)	205,949	61,816	61,860	647,159
Operating income	210,345		137,945	52,786	19,056	558
Interest and other income	2,851	(27,229)	1,098	1,374	(43)	27,651
Earnings from unconsolidated affiliates	5,008		258		4,677	73
Minority interest	183					183
Debt expense	(28,158)	27,229	(20,928)	(2,570)	(2,717)	(29,172)
Income taxes	(69,126)		(43,420)	(18,385)	(7,640)	319
Net income (loss) before accounting change	121,103		74,953	33,205	13,333	(388)
Cumulative effect of change in accounting for asset retirement obligations	(5,113)		(4,550)	(563)		
Net income (loss)	$ 115,990		$ 70,403	$ 32,642	$ 13,333	($ 388)
Identifiable assets	$1,645,961		$ 990,256	$267,742	$143,742	$244,221
Investment in unconsolidated affiliates	36,393		172		35,485	736
Capital expenditures	226,761		156,087	37,362	31,379	1,933
2002						
Revenues						
From unaffiliated customers	$ 522,476		$ 270,843	$ 8,699	$ 30,670	$212,264
From affiliated companies	106,647	($126,836)	1,262	94,827	20,908	116,486
	629,123	(126,836)	272,105	103,526	51,578	328,750
Operating expenses						
Cost of natural gas and other products sold	202,132	(122,414)	4,337		308	319,901

Operating expenses	131,598	(4,422)	79,686	18,877	33,310	4,147
Depreciation, depletion and amortization	117,446		88,888	20,475	7,361	722
Exploration	6,086		6,086			
Abandonment and impairment of gas, oil and other properties	11,183		11,183			
Production and other taxes	28,558		17,521	10,374	614	49
Wexpro Agreement - oil income sharing	1,676			1,676		
Total operating expenses	498,679	(126,836)	207,701	51,402	41,593	324,819
Operating income	130,444		64,404	52,124	9,985	3,931
Interest and other income	50,894	(32,262)	47,221	555	2,882	32,498
Earnings from unconsolidated affiliates	3,977		40		3,730	207
Minority interest	484					484
Debt expense	(34,705)	32,262	(26,167)	(4,570)	(2,125)	(34,105)
Income taxes	(53,165)		(29,316)	(17,318)	(5,353)	(1,178)
Net income	$97,929		$ 56,182	$ 30,791	$ 9,119	$1,837
Identifiable assets	$1,525,117		$1,012,555	$226,020	$158,978	$127,564
Investment in unconsolidated affiliates	23,617		212		22,559	846
Capital expenditures	185,990		125,946	27,452	31,165	1,427

Prior to its sale in the fourth quarter of 2002, Market Resources' Canadian subsidiary reported revenues, measured in U. S. dollars, totaling $21.7 million for the year ended December 31, 2002.

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 managed and developed by Wexpro.

Nonregulated Activities

This information pertains to Questar E&P gas and oil activities. Cost-of-service activities are presented in a separate section of this note.

Gas and Oil Exploration and Development Activities

The following information is provided with respect to Market Resources' gas and oil exploration and development activities, which are located exclusively in the United States. The Company sold its Canadian subsidiary in the fourth quarter of 2002.

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. Future-abandonment costs associated with asset-retirement obligations amounted to $25.0 million and $23.5 million at December 31, 2004 and 2003, respectively. These costs are included in proved properties and support equipment and facilities.

	December 31, 2004	December 31, 2003
	(in thousands)	
Proved properties	$1,602,143	$1,315,330
Unproved properties	62,678	95,208
Support equipment and facilities	16,932	22,569
	1,681,753	1,433,107
Accumulated depreciation, depletion and amortization	600,366	501,825
	$1,081,387	$ 931,282

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 $80.1 million, $55.3 million and $51.1 million in 2004, 2003 and 2002, respectively.

	Year Ended December 31,				
	2004	2003		2002	
	Total	Total	United States	Canada	Total
			(in thousands)		
Property acquisition					
Unproved	$ 13,346	$ 3,779	$ 1,092	$ 119	$ 1,211
Proved	1,205	1,039	45		45
Exploration	25,059	13,521	10,372	627	10,999
Development	238,012	155,226	121,763	3,268	125,031
Asset-retirement obligations	1,699	1,616			
	$279,321	$175,181	$133,272	$4,014	$137,286

Results of Operations

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

	Year Ended December 31,				
	2004	2003		2002	
	Total	Total	United States	Canada	Total
			(in thousands)		
Revenues					
From unaffiliated customers	$448,796	$343,894	$249,239	$21,694	$270,933
From affiliates			1,172		1,172
Total revenues	448,796	343,894	250,411	21,694	272,105
Production expenses	98,962	77,167	63,149	6,924	70,073
Exploration	9,239	4,498	5,459	627	6,086
Depreciation, depletion and amortization	105,451	88,901	81,473	7,415	88,888
Accretion expense (asset-retirement obligations)	2,001	1,852			
Abandonment and impairment of gas, oil and other properties	12,968	4,151	11,030	153	11,183
Total expenses	228,621	176,569	161,111	15,119	176,230
Revenues less expenses	220,175	167,325	89,300	6,575	95,875
Income taxes - Note A	77,502	61,409	27,057	4,228	31,285
Results of operations before corporate overhead, interest and cumulative effect of accounting change	142,673	105,916	62,243	2,347	64,590
Cumulative effect of accounting change for asset retirement obligations		(4,550)			
Results of operations before corporate overhead and interest expenses	$142,673	$101,366	$ 62,243	$ 2,347	$ 64,590

Note A - Income tax expenses have been reduced by nonconventional fuel-tax credits of $4.9 million in 2002. The availability of these credits ended after December 31, 2002.

Estimated Quantities of Proved Gas and Oil Reserves

The table below shows the estimated proved reserves owned by the Company. Estimates of U.S. reserves were prepared by Ryder Scott Company, Netherland, Sewell & Associates, H. J. Gruy and Associates, Inc., and Malkewicz Hueni Associates Inc., independent reservoir engineers. Estimates of Canadian reserves were prepared by Gilbert Laustsen Jung Associates Ltd, and Sproule

Associates Limited, independent reservoir engineers. 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. The quantities reported below are based on existing economic and operating conditions at December 31. All gas and oil reserves reported were located in the United States and Canada. Canadian properties were sold in the fourth quarter of 2002. The Company does not have any long-term supply contracts with foreign governments or reserves of equity investees.

	Natural Gas			Oil		
	United States	Canada	Total	United States	Canada	Total
		(MMcf)			(Mbbl)	
Balance at January 1, 2002	936,147	61,829	997,976	27,738	3,334	31,072
Revisions of estimates	(108,570)	701	(107,869)	(800)	122	(678)
Extensions and discoveries	240,872	1,712	242,584	2,812	26	2,838
Purchase of reserves in place	42		42			
Sale of reserves in place	(43,220)	(59,433)	(102,653)	(270)	(3,028)	(3,298)
Production	(74,865)	(4,809)	(79,674)	(2,310)	(454)	(2,764)
Balance at December 31, 2002	950,406		950,406	27,170		27,170
Revisions of estimates	14,057		14,057	445		445
Extensions and discoveries	111,575		111,575	1,285		1,285
Purchase of reserves in place	2,098		2,098	8		8
Sale of reserves in place	(152)		(152)	(3)		(3)
Production	(78,811)		(78,811)	(2,324)		(2,324)
Balance at December 31, 2003	999,173		999,173	26,581		26,581
Revisions of estimates	(32,442)		(32,442)	(1,027)		(1,027)
Extensions and discoveries	392,810		392,810	3,964		3,964
Purchase of reserves in place	812		812	5		5
Sale of reserves in place	(21)		(21)			
Production	(89,801)		(89,801)	(2,281)		(2,281)
Balance at December 31, 2004	1,270,531		1,270,531	27,242		27,242
Proved-Developed Reserves						
Balance at January 1, 2002	534,761	53,036	587,797	19,417	2,566	21,983
Balance at December 31, 2002	540,333		540,333	19,942		19,942
Balance at December 31, 2003	612,181		612,181	20,504		20,504
Balance at December 31, 2004	680,587		680,587	21,293		21,293

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 $5.50 in 2004, $5.57 in 2003 and $3.34 in 2002. The average year-end price per barrel of proved oil and NGL reserves combined was $40.60 in 2004, $30.45 in 2003 and $28.46 in 2002. 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. The statutes allowing income tax credits for nonconventional fuels expired for production after December 31, 2002. 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 $122.5 million, $146.6 million and $128.1 million in 2005, 2006 and 2007, respectively. At the end of this three-year period the Company expects to have evaluated about 61% of the currently 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,

	2004	2003	2002
	(in thousands)		
Future cash inflows	$8,090,022	$6,378,076	$3,951,706
Future production costs	(1,723,128)	(1,403,893)	(1,049,205)
Future development costs	(663,051)	(338,245)	(326,169)
Future asset-retirement obligations	(104,356)	(96,187)	
Future income tax expenses	(1,854,458)	(1,514,814)	(768,402)
Future net cash flows	3,745,029	3,024,937	1,807,930
10% annual discount to reflect timing of net cash flows	(1,984,491)	(1,494,924)	(908,304)
Standardized measure of discounted future net cash flows	$1,760,538	$1,530,013	$899,626

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

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Beginning balance	$1,530,013	$ 899,626	$604,302
Sales of gas and oil produced, net of production costs	(349,834)	(266,726)	(202,031)
Net changes in prices and production costs	(37,786)	820,131	535,315
Extensions and discoveries, less related costs	763,776	235,891	298,082
Revisions of quantity estimates	(70,767)	33,092	(128,917)
Purchase of reserves in place	1,205	1,039	45
Sale of reserves in place	(1,363)	(8,610)	(126,485)
Change in future development	(123,508)	7,448	(12,128)
Accretion of discount	153,001	89,963	60,430
Net change in income taxes	(28,968)	(345,600)	(138,387)
Change in production rate	(161,734)	21,091	(11,229)
Asset-retirement obligations and other	86,503	42,668	20,629
Net change	230,525	630,387	295,324
Ending balance	$1,760,538	$1,530,013	$899,626

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. Future-abandonment costs associated with asset-retirement obligations amounted to $8.8 million and $8.2 million at December 31, 2004 and 2003, respectively.

	December 31,	
	2004	2003
	(in thousands)	
Wexpro	$253,639	$233,947
Questar Gas	16,054	17,194
	$269,693	$251,141

Costs Incurred

Costs incurred by Wexpro for cost-of-service gas and oil-producing activities were $43.6 million including $0.6 million associated with asset-retirement obligations in 2004, $36.6 million including $0.3 million associated with asset retirement obligations in 2003 and $26.7 million in 2002.

Results of Operations

Following are the results of operations of Wexpro's cost-of-service gas and oil-development activities, before corporate overhead and interest expenses.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Revenues			
From unaffiliated companies	$ 17,315	$ 13,006	$ 8,699
From affiliates – Note A	115,637	101,596	94,827
Total revenues	132,952	114,602	103,526
Production expenses	40,613	32,670	23,032
Depreciation and amortization	21,038	20,169	20,475
Accretion expense (asset-retirement obligations)	3,993	183	
Abandonment and impairment of gas and oil properties	2,790		
Total expenses	68,434	53,022	43,507
Revenues less expenses	64,518	61,580	60,019
Income taxes	23,167	22,134	21,572
Results of operations before corporate overhead, interest expenses and cumulative effect of accounting change	41,351	39,446	38,447
Cumulative effect of accounting change for asset-retirement obligations		(563)	
Results of operations before corporate overhead and interest expense	$41,351	$38,883	$38,447

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 managed 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 Wexpro's reservoir engineers.

	Natural Gas	Oil
	(MMcf)	(Mbbl)
Proved Reserves		
Balance at January 1, 2002	405,681	3,687
Revisions of estimates	(658)	(122)
Extensions and discoveries	56,085	675
Production	(41,208)	(501)
Balance at December 31, 2002	419,900	3,739
Revisions of estimates	24,273	103
Extensions and discoveries	30,286	187
Production	(40,088)	(449)
Balance at December 31, 2003	434,371	3,580
Revisions of estimates	5,624	32
Extensions and discoveries	129,855	1,018
Production	(38,758)	(424)

Balance at December 31, 2004	531,092	4,206
Proved-Developed Reserves		
Balance at January 1, 2002	400,461	3,640
Balance at December 31, 2002	395,821	3,481
Balance at December 31, 2003	406,144	3,330
Balance at December 31, 2004	409,194	3,202

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 thousands)		
Year Ended December 31, 2004				
Allowance for bad debts	$4,133	($709)	($620)	$2,804
Year Ended December 31, 2003				
Allowance for bad debts	3,759	432	58	4,133
Year Ended December 31, 2002				
Allowance for bad debts	2,849	1,207	297	3,759

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.

a. 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-14(c) under the Act as of a date within 90 days prior to the filing date of this quarterly 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 Act.

b. Changes in Internal Controls. Since the Evaluation Date, there have not been any material changes in the Company's internal controls or other factors that could materially affect such controls.

ITEM 9B. OTHER INFORMATION.

There is no information to report in this section.

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 ACCOUNTANT 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:

	2004	2003
Audit Fees	$1,267,461	$562,147
Market Resources Portion	599,869	238,291
Audit-related Fees	46,000	43,500
Market Resources Portion	19,570	14,833
Tax Fees		
	3,725	9,875

Market Resources Portion	1,649	4,126
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
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.)
4.1.*	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.) [1]
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.*	First Amendment to Credit Agreement dated October 25, 2004 by and among the Company, Bank of America, N.A. and other leaders. (Exhibit No. 4.5. to the Company's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2004.)
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.)
24.	Power of Attorney.
31.1.	Certification signed by C. B. Stanley, Market Resources' Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Act
31.2.	Certification signed by S. E. Parks, Market Resources' Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Act.

*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 29th day of March, 2005.

QUESTAR MARKET RESOURCES, INC.
(Registrant)

By: /s/C. B. Stanley
C. B. Stanley
President & 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 & 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	General Manager, Accounting (Principal Accounting Officer)
*Keith O. Rattie	Chairman of the Board; Director
*Phillips S. Baker, Jr.	Director
*Teresa Beck	Director
*R. D. Cash	Director
Patrick J. Early	Director
*L. Richard Flury	Director
*James A. Harmon	Director
*Robert E. McKee III	Director
*M. W. Scoggins	Director
*C. B. Stanley	Director

March 29, 2005 Date	*By	/s/C. B. Stanley C. B. Stanley, Attorney in Fact

Exhibits List

Exhibit No.	Description
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.)
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*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 3.4.

BYLAWS
OF
QUESTAR MARKET RESOURCES, INC.
A Utah Corporation
as amended February 8, 2005

OFFICES

SECTION 1. The Company's principal office shall be in Salt Lake City, Utah. The Company may also have offices at such other places as the Board of Directors may from time to time appoint or the business of the Company may require.

SEAL

SECTION 2. The corporate seal shall have inscribed thereon the name of the Company, and the words "Corporate Seal," and "Utah."

SHAREHOLDERS' MEETINGS

SECTION 3. The annual meeting of stockholders shall be held on the third Tuesday in May at such time and in such location as set by the Chairman of the Board, provided that advance notice of the time and location of such meeting shall be given to stockholders and directors. At the annual meeting, the stockholders shall elect directors by majority vote and transact such other business as may properly be brought before the meeting.

SECTION 4. Special meetings of the shareholders may be called by the President, the Board of Directors, or holders of not less than one-tenth of all the shares entitled to vote at the meeting.

SECTION 5. Holders of a majority of the shares issued and outstanding entitled to vote, present in person or represented by proxy, shall constitute a quorum at all meetings of the shareholders for the transaction of business, except as otherwise provided by law, by the Articles of Incorporation, or by these Bylaws. If, however, such majority shall not be present or represented at any meeting of the shareholders, the shareholders entitled to vote present in person or by proxy, shall have power to adjourn the meeting, from time to time, without notice other than announcement at the meeting, until such requisite amount of voting stock shall be present. At such adjourned meeting at which the requisite amount of voting stock shall be represented, any business may be transacted that might have been transacted at the meeting as originally notified.

SECTION 6. The Secretary shall, but in case of his failure any other office of the Company may, give written or printed notice to the shareholders stating the place, day and hour of each shareholders' meeting and, in case of a special meeting, the purpose or purposes for which the meeting is called. Such notice shall be given not less than ten (10) nor more than fifty (50) days before the date of the meeting.

SECTION 7. Notice may be given either personally or by mail, and if given by mail, such notice shall be deemed to be delivered when deposited in the United States mail addressed to the shareholder at his address as it appears on the stock transfer books of the Company with postage prepaid thereon.

SECTION 8. At any meeting of shareholders, each shareholder having the right to vote shall be entitled to vote in person or by proxy appointed by an instrument in writing, subscribed by such shareholder and bearing a date not more than three months prior to such meeting. Each shareholder shall have one vote for each share of stock registered in such shareholder's name on the books of the Company as of the record date set for such meeting. The vote for directors, and upon the demand of any shareholder, the vote upon any question before any meeting of shareholders shall be by ballot.

SECTION 9. A complete list of shareholders entitled to vote at the ensuing election shall be prepared and be available for inspection by any shareholder beginning two business days after notice is given of the meeting for which the list was prepared and continuing throughout the meeting. The list shall be arranged by voting group and by class or series of shares within each voting group and be alphabetical within each voting group or class. The list shall indicate each shareholder's name, address, and number of voting shares.

A shareholder, directly or through an agent or attorney, has the right to inspect and copy, at his expense, the list of shareholders prepared for each meeting of shareholders. The shareholder must make a written request to examine the list and must examine it during the Company's regular business hours.

SECTION 10. Business transacted at all special meetings of the shareholders shall be confined to the objects stated in the call and notice.

SECTION 11. Unless otherwise provided in the Articles of Incorporation, any action that may be taken at any annual or special meeting of the shareholders may be taken without a meeting and without prior notice upon the receipt of a unanimous written consent.

DIRECTORS

SECTION 12. The business and affairs of the Company shall be managed under the direction of the Board of Directors. The Board of Directors shall consist of no less than three and no more than eleven directors. A majority of the Board shall have the power to transact the business of the Company in conformity with the powers conferred upon the Board of Directors by the Articles of Incorporation. Directors elected at any annual or special meeting of shareholders shall hold office until the next annual meeting of the shareholders and until their successors shall be duly elected. The Board of Directors has the power to appoint a director to serve until the next annual meeting of shareholders. One or more directors may be removed with or without cause by a vote of a majority of the shareholders at a meeting of shareholders called for that purpose.

COMMITTEE

SECTION 13. The Board of Directors, by resolution or resolutions passed by a majority of the whole Board, may designate one or more Committees, each Committee to consist of two or more of the directors of the Company and shall have and may exercise the powers conferred upon them by the Board of Directors. All Committees when so appointed shall have such name or names as may be determined from time to time by resolutions adopted by the Board of Directors.

SECTION 14. The Committees shall keep regular minutes for their proceedings and report the same to the Board of Directors when required.

COMPENSATION OF DIRECTORS

SECTION 15. Directors, as such, shall not receive any salary for their services, but the Board of Directors, by resolution, may fix the fees to be allowed and paid to directors for their services and provide for the payment of the expenses of the directors incurred by them in performing their duties. Nothing herein contained, however, shall be considered to preclude any director from serving the Company in any other capacity and receiving compensation therefore.

SECTION 16. Fees to members of special or standing committees and expenses incurred by them in the performance of their duties shall also be fixed and allowed by resolution of the Board of Directors.

MEETINGS OF THE BOARD

SECTION 17. The Board of Directors may meet at Salt Lake City, Utah, or at such other place as may be determined by a majority of the members of the Board.

SECTION 18. Regular meetings of the Board may be held without notice at such time and place as shall from time to time be determined by the Board.

SECTION 19. Special meetings of the Board may be called by the President on at least two days' notice to each director, either personally or by mail, telegram or telephone; special meetings shall be called by the President or Secretary in like manner and on like notice on the written request of two directors.

SECTION 20. At all meetings of the Board a majority of the directors shall be necessary and sufficient to constitute a quorum for the transaction of business. The act of a majority of the directors present at any meeting at which there is a quorum shall be the act of the Board of Directors. Directors may participate in a Board meeting and can be counted in a quorum by means of conference telephone or similar communications equipment by which all directors participating in the meeting can hear each other.

SECTION 21. Unless the Articles of Incorporation provide otherwise, any acts required or permitted to be taken by the Board of Directors at a meeting may be taken without a meeting if all the directors take the action, each director signs a written consent describing the action taken, and the consents are filed with the records of the Company. Action taken by consent is effective when the last director signs the consent, unless the consent specifies a different effective date. A signed consent has the effect of a meeting vote and may be described as such in any document.

SECTION 22. The officers of the Company shall be chosen by the Board of Directors at its first meeting after each annual meeting and shall include: a Chairman of the Board, a President and Chief Executive Officer, a Vice President, a Secretary and a Treasurer. The Board may also choose a Vice Chairman of the Board, and additional Vice Presidents, Assistant Secretaries and Assistant Treasurers. None of these officers except the Chairman of the Board, the Vice Chairman of the Board, and the President need be members of the Board.

SECTION 23. The Board may appoint such other officers and agents as it may deem necessary. Such officers and agents shall hold their office for such terms and shall exercise such powers and perform such duties as shall be determined from time to time by the Board.

SECTION 24. The salaries of all officers of the Company shall be fixed by the Board of Directors.

SECTION 25. The officers of the Company shall hold office until their successors are chosen and qualified in their stead. Any officer elected or appointed by the Board of Directors may be removed at any time by the affirmative vote of a majority of the whole Board of Directors. If the office of any officer or officers becomes vacant for any reason, the vacancy shall be filled by the affirmative vote of a majority of the whole Board of Directors.

CHAIRMAN OF THE BOARD

SECTION 26. The Chairman of the Board shall preside at the meetings of the shareholders and directors.

VICE CHAIRMAN OF THE BOARD

SECTION 27. The Vice Chairman of the Board shall preside at all meetings of the shareholders and directors in the absence of the Chairman.

PRESIDENT

SECTION 28. The President shall be the Chief Executive Officer of the Company; shall preside at all meetings of the shareholders and directors in the absence of the Chairman of the Board and the Vice Chairman of the Board (if there be one); shall have general and active management of the business of the Company; and shall see that all orders and resolutions of the Board are carried into effect. He shall have the general powers and duties of supervision and management usually vested in the office of President and Chief Executive Officer of a corporation. He shall perform such other functions and duties as shall be prescribed by the Board of Directors.

VICE PRESIDENT

SECTION 29. Each Vice President shall perform the duties prescribed by the President or the Board of Directors. If the President shall become unable for any reason to perform his duties, then the Vice President, or if there is more than one Vice President, the one designated as Senior Vice President (if any) or the one designated by the Board of Directors shall succeed to the duties of the President until the President shall again become able to perform his duties.

SECRETARY AND ASSISTANT SECRETARIES

SECTION 30. (a) The Secretary shall attend the meetings of the Board and the meetings of the shareholders and record all votes and the minutes of all proceedings in a book to be kept for that purpose and shall perform like duties for the Committees appointed by the Board when required; give or cause to be given notice of the meetings of the shareholders and of the Board of Directors; and perform such other duties as may be prescribed by the Board of Directors or President.

(b) The Assistant Secretary, senior in time of service, in the absence or disability of the Secretary, shall perform the duties and exercise the powers of the Secretary and shall perform such other duties as shall be prescribed by the President or the Board of Directors.

TREASURER AND ASSISTANT TREASURERS

SECTION 31. The Treasurer and Assistant Treasurers shall perform such duties as shall be prescribed by the President or the Board.

VACANCIES

SECTION 32. If the office of any director or directors becomes vacant by reason of the death, resignation, disqualification, removal from office, or otherwise, the remaining directors, not less than a quorum, shall choose a person or persons to fill the vacancy or vacancies who shall hold office until the successor or successors shall have been duly appointed or elected.

CERTIFICATES OF STOCK

SECTION 33. The certificates of stock of the Company shall be numbered and shall be entered in the books of the Company as they are issued.

FISCAL YEAR

SECTION 34. The fiscal year shall begin the first day of January in each year.

RECORDS AND INSPECTION RIGHTS

SECTION 35. The Company shall maintain permanent records of the minutes of all meetings of its shareholders and Board of Directors; all actions taken by the shareholders or Board of Directors without a meeting; and all actions taken by a Committee of the Board of Directors in place of the Board of Directors on behalf of the Company. The Company shall also maintain appropriate accounting records. The Company shall keep such records at its office in Salt Lake City, Utah, and any other location designated by the Board of Directors.

A shareholder of the Company, directly or through an agent or attorney, shall have limited rights to inspect and copy the Company's records as provided under applicable state law and by complying with the procedures specified under such law.

BANK ACCOUNTS

SECTION 36. All checks, demands for money, or other transactions involving the Company's bank accounts shall be signed by such officers or other responsible employees as the Board of Directors may designate. No third party is allowed access to the Company's bank accounts without express written authorization by the Board of Directors.

AMENDMENTS

SECTION 37. The Company's Board of Directors may amend or repeal the Company's Bylaws unless the Company's Articles of Incorporation or Utah's Revised Business Corporation Act reserve this power exclusively to the shareholders in whole or part; unless the shareholders, in adopting, amending, or repealing a particular Bylaw provide expressly that the Board of Directors may not amend or repeal that Bylaw; or unless the Bylaw establishes, amends, or deletes a supermajority shareholder quorum or voting requirement. The Company's shareholders may amend or repeal the Company's Bylaws even though the Bylaws may also be amended or repealed by the Board of Directors.

INDEMNIFICATION AND LIABILITY INSURANCE

SECTION 38. (a) Voluntary Indemnification. Unless otherwise provided in the Articles of Incorporation, the Company shall indemnify any individual made a party to a proceeding because he is or was a director of the Company, against liability incurred in the proceeding, but only if the Company has authorized the payment in accordance with the applicable statutory provisions [Sections 16-10a-902 and 16-10a-904 of Utah's Revised Business Corporation Act] and a determination has been made in accordance with the procedures set forth in such provision that the director conducted himself in good faith; that he reasonably believed that his conduct, if in his official capacity with the Company, was in its best interests and that his conduct, in all other cases, was at least not opposed to the Company's best interests; and that he had no reasonable cause to believe his conduct was unlawful in the case of any criminal proceeding.

(b) The Company may not voluntarily indemnify a director in connection with a proceeding by or in the right of the Company in which the director was adjudged liable to the Company or in connection with any other proceeding charging improper personal benefit to him, whether or not involving action in his official capacity, in which he was adjudged liable on the basis that personal benefit was improperly received by him.

(c) Indemnification permitted under Paragraph (a) in connection with a proceeding by or in the right of the Company is limited to reasonable expenses incurred in connection with the proceeding.

(d) If a determination is made, using the procedures set forth in the applicable statutory provision, that the director has satisfied the requirements listed herein and if an authorization of payment is made, using the procedures and standards set forth in the applicable statutory provision, then, unless otherwise provided in the Company's Articles of Incorporation, the Company shall pay for or reimburse the reasonable expenses incurred by a director who is a party to a proceeding in advance of the final disposition of the proceeding if the director furnishes the Company a written affirmation of his good faith belief that he has satisfied the standard of conduct described in this Section, furnishes the Company a written undertaking, executed personally or on his behalf, to repay the advance if it is ultimately determined that he did not meet the standard of conduct (which undertaking must be an unlimited general obligation of the director, but need not be secured and may be accepted without reference to financial ability to make repayment); and if a determination is made that the facts then known of those making the determination would not preclude indemnification under this Section.

(e) Mandatory Indemnification. Unless otherwise provided in the Company's Articles of Incorporation, the Company shall indemnify a director or officer of the Company who was wholly successful, on the merits or otherwise, in the defense of any proceeding to which he was a party because he is or was a director or officer of the Company against reasonable expenses incurred by him in connection with the proceeding.

(f) Court-Ordered Indemnification. Unless otherwise provided in the Company's Articles of Incorporation, a director or officer of the Company who is or was a party to a proceeding may apply for indemnification to the court conducting the proceeding or to another court of competent jurisdiction. The court may order indemnification if it determines that the director or officer is entitled to mandatory indemnification as provided in this Section and applicable law, in which case the court shall also order the Company to pay the reasonable expenses incurred by the director or officer to obtain court-ordered indemnification. The court may also order indemnification if it determines that the director or officer is fairly and reasonably entitled to indemnification in view of all the relevant circumstances, whether or not the director or officer met the applicable standard of conduct set forth in this Section and applicable law. Any indemnification with respect to any proceeding in which liability has been adjudged in the circumstances described in Paragraph (b) above is limited to reasonable expenses.

(g) Indemnification of Others. Unless otherwise provided in the Company's Articles of Incorporation, an officer, employee, or agent of the Company shall have the same indemnification rights provided to a director by this Section. The Board of Directors may also indemnify and advance expenses to any officer, employee, or agent of the Company, to any extent consistent with public policy as determined by the general or specific purpose of the Board of Directors.

(h) Insurance. The Company may purchase and maintain liability insurance on behalf of a person who is or was a director, officer, employee, fiduciary, or agent or the Company, or who, while serving as a director, officer, employee, fiduciary, or agent of the Company, is or was serving at the request of the Company as a director, officer, partner, trustee, employee, fiduciary or agent of another foreign or domestic corporation, other person, of an employee benefit plan, or incurred by him in that capacity or arising from his status as a director, officer, employee, fiduciary, or agent, whether or not the Company has the power to indemnify him against the same liability under applicable law.

LIMITATION ON LIABILITY

SECTION 39. No director of the Company shall be personally liable to the Company or its stockholders for monetary damages for any action taken or any failure to take any action, as a director, except liability for (a) the amount of a financial benefit received by a director to which he is not entitled; (b) an intentional infliction of harm on the Company or the shareholders; (c) for any action that would result in liability of the director under the applicable statutory provision concerning unlawful distributions [Section 16-10a-842 of Utah's Revised Business Corporation Act]; or (d) an intentional violation of criminal law. This provision shall not limit the liability of a director for any act or omission occurring prior to August 11, 1992. Any repeal or modification of this provision by the stockholders shall be prospective only and shall not adversely affect any limitation on the personal liability of a director of the Company for acts or omissions occurring prior to the effective date of such repeal or modification.

Exhibit No. 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 2004 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 2004 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 K. O. Rattie	Chairman of the Board	2-08-05
/s/C. B. Stanley C. B. Stanley	President and Chief Executive Officer Director	2-08-05
/s/Phillips S. Baker Jr. Phillips S. Baker	Director	2-08-05
/s/Teresa Beck Teresa Beck	Director	2-08-05
/s/R. D. Cash R. D. Cash	Director	2-08-05
P. J. Early	Director	2-08-05
/s/L. Richard Flury	Director	2-08-05

L. Richard Flury

/s/James A. Harmon James A. Harmon	Director	2-08-05
/s/Robert E. McKee, III Robert E. McKee	Director	2-08-05
/s/M. W. Scoggins M. W. Scoggins	Director	02-08-05

Exhibit No. 31.1.

CERTIFICATION

I, C. B. Stanley, certify that:

1. I have reviewed this Annual Report on Form 10-K for 2004 of Questar Market Resources, Inc.;

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 annual 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) 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

   (d) 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; and

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 29, 2005 Date	By: /s/C. B. Stanley C. B. Stanley

President and Chief Executive Officer

Exhibit No. 31.2.

CERTIFICATION

I, S. E. Parks, certify that:

1. I have reviewed this Annual Report on Form 10-K for 2004 of Questar Market Resources, Inc.;

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 annual 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) 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

   (d) 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; and

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 29, 2005
Date

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

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