QUESTAR CORP
Form 10-K
March 02, 2006

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the Year Ended December 31, 2005

Commission File Number 1-8796

QUESTAR CORPORATION

STATE OF UTAH	1-8796	87-0407509
(State of other jurisdiction of incorporation or organization)	(Commission File No.)	(I.R.S. Employer Identification No.)

Phone: (801) 324-5000

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

Common stock, without par value,

with attached common stock purchase rights

The above Securities are listed on the New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X]   No [ ]

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

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

Large accelerated filer [X]   Accelerated filer [ ]   Non-accelerated filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ]   No [X]

Aggregate market value of the voting common equity held by non-affiliates of the registrant as of the last business day of the registrant s most recently completed second quarter (June 30, 2005): $5,572,015,000 *

On February 28, 2006, 85,488,814 shares of the registrant s common stock, without par value, were outstanding.

Documents Incorporated by Reference. Portions of the registrant s definitive Proxy Statement for the 2006 Annual Meeting of Stockholders to be held on May 16, 2006, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2005, are incorporated by reference into Part III. The sections of the Proxy Statement labeled Committee Report on Executive Compensation and Cumulative Total Shareholder Returns are expressly not incorporated into this document.

*Calculated by excluding all shares held by directors and executive officers of registrant and three nonprofit foundations established by registrant without conceding that all such persons are affiliates for purposes of federal securities laws.

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Where You Can Find More Information

Questar Corporation (Questar) and its principal subsidiaries, Questar Market Resources, Inc., Questar Pipeline Company and Questar Gas Company, each file annual, quarterly, and current reports with the Securities and Exchange Commission (SEC). Questar also regularly files proxy statements and other documents with the SEC. The public may read and copy these reports and any other materials filed with the SEC at its Public Reference Room at 450 Fifth

Street, N.W., Washington, D.C. 20549-0213. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. The SEC also maintains a 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 via Questar s website at www.questar.com. Questar and each of its reporting subsidiaries make available, free of charge, through the website copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports and all reports filed by executive officers and directors under Section 16 of the Exchange Act reporting transactions in Questar securities. Access to these reports is provided as soon as reasonably practical after such reports are electronically filed with the SEC. Questar s website also contains Statements of Responsibility for Board Committees, Corporate Governance Guidelines and its Business Ethics and Compliance Policy.

Finally, you may request a copy of filings, other than an exhibit to a filing unless that exhibit is specifically incorporated by reference into that filing, at no cost by writing or calling Questar, 180 East 100 South Street, P.O. Box 45433, Salt Lake City, Utah 84145-0433 (telephone number (801) 324-5000).

Forward-Looking Statements

This Annual Report may contain or incorporate by reference information that includes or is based upon forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as anticipate, estimate, expect, project, intend, plan, believe, and other words a similar meaning in connection with a discussion of future operating or financial performance. In particular, these include statements relating to future actions, prospective services or products, future performance or results of current and anticipated services or products, exploration efforts, expenses, the outcome of contingencies such as legal proceedings, trends in operations and financial results.

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

- the risk factors discussed in Part I, Item 1A. of this Annual Report;

- general economic conditions, including the performance of financial markets and interest rates;
- changes in industry trends;
- changes in laws or regulations; and
- other factors, most of which are beyond control.

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

Glossary of Commonly Used Terms

B

Billion

bbl

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

basis

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

Btu

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

cash-flow hedge

A derivative instrument that complies with Statement of Financial Accounting Standards (SFAS) 133, as amended, and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas and oil production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

cf

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

cfe

Cubic feet of natural gas equivalents

development well

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

dewpoint

A specific temperature and pressure at which hydrocarbons condense to form a liquid.

dry hole

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

dth

Decatherms or ten therms. One dth equals one million Btu or approximately one Mcf.

dthe

Decatherms of natural gas equivalents

equity production

Production at the wellhead attributed to Questar ownership.

exploratory well

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

finding costs

Finding costs are the sum of costs incurred for gas and oil exploration and development activities; including purchases of reserves in place, leasehold acquisitions, seismic, geological and geophysical, development and exploration drilling and asset retirement obligations for a given period, divided by the total amount of estimated net proved reserves added through discoveries, positive and negative revisions and purchases in place for the same period. The Company expresses finding costs in dollars per Mcfe averaged over a five-year period.

frac spread

The difference between the market price for NGLs extracted from the gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids.

futures contract

An exchange-traded contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.

gal

U.S. gallon.

gas

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

gross

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

heating degree days

A measure of the number of degrees the average daily outside temperature is below 65 degrees Fahrenheit.

hedging

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

infill development drilling

Drilling wells between established producing wells; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons.

lease operating expenses

The expenses, usually recurring, which are incurred to operate the wells and equipment on a producing lease.

M

Thousand.

MM

Million.

natural gas equivalents

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

natural gas liquids (NGL)

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

net

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

net revenue interest

A share of production after all burdens, such as royalties and overriding royalties, have been deducted from the working interest. It is the percentage of production that each owner actually receives.

production replacement ratio

The production replacement ratio is calculated by dividing the net proved reserves added through discoveries, positive and negative revisions and purchases and sales in-place for a given period by the production for the same period, expressed as a percentage. The production replacement ratio is typically reported on an annual basis.

proved reserves

Those quantities of natural gas, crude oil, condensate and NGL on a net revenue interest basis, which geological and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions. See 17 C.F.R. Section 4-10(a)(2) for a complete definition.

proved developed reserves

Reserves that include proved developed producing reserves and proved developed nonproducing reserves. See 17 C.F.R. Section 4-10(a)(3).

proved developed producing reserves

Reserves expected to be recovered from existing completion intervals in existing wells.

proved undeveloped reserves

Reserves expected to be recovered from new wells on proved undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 4-10(a)(4).

reservoir

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

royalty

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

seismic

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

wet gas

Unprocessed natural gas that contains a mixture of heavier hydrocarbons including ethane, propane, butane and natural gasoline.

working interest

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

workover

Operations on a producing well to restore or increase production.

FORM 10-K

ANNUAL REPORT, 2005

PART I

ITEM 1. BUSINESS.

Nature of Business

Questar Corporation (Questar or the Company) is a natural gas-focused energy company with four major lines of business gas and oil exploration and production, midstream field services, interstate gas transportation, and retail gas distribution which are conducted through its three principal subsidiaries. Questar Market Resources, Inc. (Market Resources) engages in gas and oil exploration, development and production and midstream field services-gas gathering and processing, as well as wholesale gas and oil marketing and gas storage. Questar Pipeline Company (Questar Pipeline) provides interstate natural gas transportation and storage services. Questar Gas Company (Questar Gas) provides retail natural gas distribution. See Note 15 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for financial information concerning Questar's lines of business that contribute 10% or more of consolidated revenues.

Questar is a holding company, as that term is defined in the Public Utility Holding Company Act of 2005 (PUHCA 2005), because its subsidiary Questar Gas is a gas utility company. Questar, however, qualifies for and will file for an exemption and waiver from provisions of the Act applicable to holding companies. PUHCA 2005 supersedes the Public Utility Holding Company Act of 1935 under which Questar qualified for an exemption. Questar conducts most of its operations through subsidiaries. The parent-holding company performs certain management, legal, tax, administrative and other services for its subsidiaries

Questar operates in the Rocky Mountain and Midcontinent regions of the United States of America and is headquartered in Salt Lake City, Utah. Shares of Questar common stock trade on the New York Stock Exchange under the symbol STR.

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

Market Resources

Market Resources is a natural gas-focused energy company, a wholly owned subsidiary of Questar and Questar s primary growth driver. Market Resources is a sub-holding company with four principal subsidiaries: Questar Exploration and Production Company (Questar E&P) acquires, explores for, develops and produces natural gas, oil, and NGL; Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas; Questar Gas Management Company (Gas Management) provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and Questar Energy Trading Company (Energy Trading) markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned limited liability company, Clear Creek Storage Company, LLC, owns and operates an underground natural gas-storage reservoir.

Questar E&P

Questar E&P operates in two core areas the Rocky Mountain region of Wyoming, Utah and Colorado and the Midcontinent region of Oklahoma, Texas and Louisiana. Questar E&P has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming 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 the assessment of deeper reservoirs under approximately 143,000 net leasehold acres in the Vermillion Basin of southwest Wyoming and northwestern Colorado. In the Midcontinent, Questar E&P has several active development projects, including an ongoing coalbed methane project in the Arkoma Basin of eastern Oklahoma and an infill development drilling project in the Elm Grove area in northwestern Louisiana. Questar E&P seeks to maintain geographical and geological diversity with its two core areas. Questar E&P has in the past and may in the future pursue acquisition of producing properties through the purchase of assets or corporate entities to expand its presence in its core areas or create a new core area.

Questar E&P reported 1,480 Bcfe of estimated proved reserves as of December 31, 2005. Approximately 80% of Questar E&P s proved reserves, or 1,179 Bcfe, were located in the Rocky Mountain region of the United States, while the remaining 20%, or 301 Bcfe, were located in the Midcontinent region. Approximately 920 Bcfe of the proved reserves reported by Questar E&P at year-end 2005 were developed, while 560 Bcfe were proved undeveloped. The majority of the proved undeveloped reserves were associated with the Company s Pinedale Anticline leasehold. Questar E&P s primary focus is natural gas. Natural gas comprised about 90% of Questar E&P s total proved reserves at year-end 2005. See Item 2 in Part I and Note 17 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for more information on Questar E&P s proved reserves.

Questar E&P Competition and Customers

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

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

Questar E&P Regulation

Questar E&P'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, Market Resources 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 wildlife 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.

Wexpro

Wexpro develops and produces gas and oil on certain properties owned by affiliate Questar Gas under the terms of a comprehensive agreement, the Wexpro Agreement. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19% on its investment in commercial wells and related facilities adjusted for working capital and reduced for deferred income taxes and depreciation its investment base. The term of the Wexpro Agreement coincides with the productive life of the gas and oil properties covered therein. Wexpro s investment base totaled $206.3 million at December 31, 2005.

Wexpro delivers natural gas production to Questar Gas at a price equal to Wexpro s cost-of-service. Wexpro cost-of-service gas satisfied 41% of Questar Gas system requirements during 2005 at cost of service pricing that is significantly lower than Questar Gas cost for purchased gas.

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

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

Wexpro operations are contractually limited to a finite set of properties set forth in the Wexpro Agreement. Advances in technology (pad drilling and multi-stage hydraulic fracture stimulation) have unlocked significant unexploited potential on many of the subject properties. Wexpro has identified $600 to $750 million of additional drilling opportunities that could support high single-digit to low double-digit growth in revenues and net income over the next five to ten years while delivering cost-of-service natural gas supplies to Questar Gas at prices competitive with alternative sources.

See Note 14 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for more information on the Wexpro Agreement.

Gas Management

Gas Management provides natural gas-gathering and processing services to affiliates and third-party producers 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 field producers for delivery to various interstate pipelines. Under a contract with Questar Gas, Gas Management also gathers cost-of-service volumes produced from properties operated by Wexpro.

Approximately 56% of Gas Management's revenues are derived from fee-based gathering and processing agreements. The remaining revenues are derived from natural gas processing margins that are in part exposed to the frac spread. To reduce processing margin risk, Gas Management has restructured many of its processing agreements with producers from keep-whole contracts to fee-based contracts. A keep-whole contract insulates producers from frac spread risk while a fee-based contract eliminates commodity price risk for the processing plant owner. To further reduce processing margin volatility associated with keep-whole contracts, Gas Management may also attempt to reduce processing margin risk with forward-sales contracts for NGL or hedge NGL prices and equivalent gas volumes with the intent to lock in a processing margin.

Energy Trading

Energy Trading markets natural gas, oil and NGL. It combines gas volumes purchased from third parties and equity production to build a flexible and reliable portfolio. As a wholesale marketing entity, Energy Trading concentrates on markets in the Rocky Mountains, Pacific Northwest and Midcontinent that are close to reserves owned by affiliates or accessible by major pipelines. It contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin, a large baseload-storage facility owned by affiliate Questar Pipeline. Energy Trading, through its 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.

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 10 to the consolidated financial statements included in Item 8 and Quantitative and Qualitative Disclosures About Market Risk in Item 7A in Part II of this Annual Report for additional information relating to hedging activities.

Questar Pipeline

Questar Pipeline is an interstate pipeline company that provides natural gas-transportation and underground storage services in Utah, Wyoming and Colorado. As a natural gas company under the Natural Gas Act of 1938, Questar Pipeline and certain subsidiary pipeline companies are regulated by the Federal Energy Regulatory Commission (FERC) as to rates and charges for storage and transportation of natural gas in interstate commerce, construction of new facilities, and extensions or abandonments of service and facilities, accounting and other activities.

Questar Pipeline and its subsidiaries own 2,499 miles of interstate pipeline with total daily capacity of 3,399 Mdth. Questar Pipeline's core-transmission system is strategically located in the Rocky Mountain area near large reserves of natural gas in six major Rocky Mountain producing areas. Questar Pipeline transports natural gas from these producing areas to other major pipeline systems and to the Questar Gas distribution system. In addition to this core system, Questar Pipeline, through a subsidiary, owns and operates the Southern Trails Pipeline, a 488-mile line that extends from the Blanco hub in the San Juan Basin to just inside the California state line.

Questar Pipeline owns and operates the Clay Basin storage facility, the largest underground- storage reservoir in the Rocky Mountain region. Through a subsidiary, Questar Pipeline also owns gathering lines and a processing plant near Price, Utah, which provides heat-content-management services for Questar Gas and carbon-dioxide extraction for third parties.

Questar Pipeline Customers, Growth and Competition

Questar Pipeline faces risk of recontracting firm capacity as contract terms expire. Questar Pipeline s transportation system is nearly fully subscribed, and firm contracts had a weighted-average remaining life of 10.9 years as of December 31, 2005. All of Questar Pipeline storage capacity is fully contracted with a weighted-average remaining life of 8.0 years as of December 31, 2005.

Questar Gas remains Questar Pipeline's largest transportation customer. During 2005, Questar Pipeline transported 116.3 MMdth for Questar Gas compared to 116.5 MMdth in 2004. Questar Gas has reserved firm-transportation capacity of 951 Mdth per day under long-term contracts, or about 50% of Questar Pipeline's reserved capacity, during the three coldest months of the year. Questar Pipeline's primary transportation agreement with Questar Gas will expire on June 30, 2017.

Questar Pipeline also transported 259.3 MMdth for nonaffiliated customers to pipelines owned by Kern River Pipeline, Northwest Pipeline, Colorado Interstate Gas, TransColorado, Wyoming Interstate Company and other systems. Questar Pipeline may be adversely affected by proposals before the FERC to establish natural gas-quality standards, specifically for hydrocarbon dewpoint. Questar Pipeline's tariff allows a higher hydrocarbon dewpoint specification than most other systems, which requires less processing by producers before natural gas volumes are delivered into Questar Pipeline's system. As a consequence, Questar Pipeline must incur higher costs to blend lower dewpoint-processed gas with wet gas and in some instances isolate processed gas for delivery to other pipelines. In effect, Questar Pipeline currently provides a bundled gas-transportation and dewpoint-management service for shippers at certain delivery points. Questar Pipeline may need to restructure its tariff to unbundle these services.

During 2005, Questar Pipeline expanded its southern system in central Utah. This expansion was completed and placed into service in the fourth quarter of the year and added 102 Mdth of daily capacity under long-term contracts.

Questar Pipeline received FERC approval for the expansion in January 2005. Also, Questar Pipeline began service to a new power plant near Mona, Utah in the second quarter of 2005. These projects will contribute about $3 million in net income per year.

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

Questar Pipeline seeks to extend and expand its core pipeline and storage business. Questar Pipeline has proposed to further expand its southern system in central Utah. In addition, Questar Pipeline and other pipelines have proposed projects to connect northwestern Colorado and southwestern Wyoming gas supplies with pipelines moving gas east out of Wyoming. Following successful open seasons in 2005, Questar Pipeline is finalizing contracts with customers to support these new projects. Questar Pipeline is also assessing the feasibility of a gas-storage project in western Wyoming.

Southern Trails Pipeline. In mid-2002, Questar Southern Trails Pipeline, a Questar Pipeline subsidiary, placed the eastern segment of the Southern Trails pipeline into service. The eastern segment extends from the San Juan Basin to inside the California border. Capacity on this segment is fully committed under contracts that expire in mid-2008 and mid-2015.

The California segment of the Southern Trails Pipeline, which extends from near the California-Arizona border to Long Beach, California, is currently not in service. Questar Pipeline is pursuing several options to sell or place this line in service.

See Note 4 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for discussion of an impairment of the California segment of Southern Trails.

Questar Pipeline   Regulation

FERC Order No. 2004 requires employees engaged in transportation system operations to function independently from employees of marketing and energy affiliates. In addition a transportation provider must treat all transportation customers on a non-discriminatory basis and must not operate its transportation system to preferentially benefit its marketing or energy affiliates. Questar Pipeline has determined that all Market Resources subsidiaries except Gas Management are marketing or energy affiliates. Questar Gas is not an energy or marketing affiliate.

Questar Pipeline is required to comply with the Pipeline Safety Improvement Act of 2002. This Act and the rules issued by the DOT require interstate pipelines and local distribution companies to implement a 10-year program of risk analysis, pipeline assessment and remedial repair for transportation pipelines located in high-consequence areas such as densely populated locations. Questar Pipeline s annual cost to comply with the Act is approximately $1 million, not including costs of pipeline replacement, if necessary.

Clay Basin Storage Gas. See Results of Operation included in Item 7 of Part II of this Annual Report for discussion of Clay Basin storage gas loss.

Questar Gas

Questar Gas distributes natural gas as a public utility in Utah, southwestern Wyoming and a small portion of southeastern Idaho. As of December 31, 2005, Questar Gas was serving 824,447 sales and transportation customers. Questar Gas is the only non-municipal gas-distribution utility in Utah, where over 96% of its customers are located. The Public Service Commission of Utah (PSCU), the Public Service Commission of Wyoming (PSCW) and the Public Utility Commission of Idaho have granted Questar Gas the necessary regulatory approvals to serve these areas. Questar Gas also has long-term franchises granted by communities and counties within its service area.

Questar Gas growth is tied to the economic growth of Utah and southwestern Wyoming. It has over 90% of the load for residential space heating and water heating in its service territory. During 2005, Questar Gas added a record 30,330 customers, a 3.8% increase.

Questar Gas faces the same risks as other local-distribution companies. These risks include revenue variations based on seasonal changes in demand, sufficient gas supplies, declining residential usage per customer, adequate distribution facilities and adverse regulatory decisions. Questar Gas's sales to residential and commercial customers are seasonal, with a substantial portion of such sales made during the heating season. The typical residential customer in Utah (defined as a customer using 115 dth per year) consumes over 77% of total gas requirements in the coldest six months of the year. Questar Gas, however, has a weather-normalization mechanism for its general-service customers. This mechanism adjusts the non-gas portion of a customer's monthly bill as the actual heating-degree days in the billing cycle are warmer or colder than normal. This mechanism reduces dramatic fluctuations in any given customer's monthly bill from year to year and reduces fluctuations in Questar Gas gross margin.

Questar Gas minimizes gas supply risks by owning natural gas reserves. During 2005, Questar Gas satisfied 41% of its system requirements with the cost-of-service gas and associated royalty-interest volumes. Wexpro produces the gas from these properties, which is then gathered by Gas Management and transported by Questar Pipeline. Questar Gas had estimated proved cost-of-service natural gas reserves of 497.3 Bcf as of year-end 2005 compared to 531.1 Bcf a year earlier. Questar Gas also has a balanced and diversified portfolio of gas-supply contracts for volumes produced in

Wyoming, Colorado, and Utah. Questar Gas has regulatory approval to include costs associated with hedging activities in its balancing account for pass-through treatment.

Questar Gas has designed its distribution system and annual gas-supply plan to handle design-day demand requirements. It periodically updates its design-day demand, the volume of gas that firm customers could use during extremely cold weather. For the 2005-06 heating season, Questar Gas used a design-day demand of 1,106 Mdth for firm customers.

Questar Gas has long-term contracts with Questar Pipeline for transportation and storage capacity at Clay Basin and three peak-day storage facilities. Questar Gas also has contracts to take deliveries at several locations on the Kern River Pipeline.

Questar Gas Regulation

As a public utility, Questar Gas is subject to the jurisdiction of the PSCU and PSCW. Natural gas sales and transportation services are made under rate schedules approved by the two regulatory commissions. Questar Gas is authorized to earn a return on equity of 11.2% in Utah and 11.83% in Wyoming. Both the PSCU and PSCW permit Questar Gas to recover gas costs through a balancing-account procedure and to reflect natural gas-price changes on a periodic, generally semi-annual basis. Questar Gas has also received permission from the PSCU and PCSW to reflect in its gas costs specified costs associated with hedging contracts.

See Note 2 of the consolidated financial statements included in Item 8 of Part II in this Annual Report for a discussion of gas-processing cost coverage.

Questar Gas has significant relationships with affiliates that have allowed it to lower its costs and improve efficiency. These affiliate relationships, however, are subject to oversight by regulatory commissions for evidence of subsidization and above-market payments.

Questar Gas is subject to the requirements of the Pipeline Safety Improvement Act. Questar Gas estimates that it will cost $4.0 to $5.0 million per year to comply with the Act, not including costs of pipeline replacement if necessary. The PSCU has allowed Questar Gas to record a regulatory asset for these incremental operating costs incurred to comply with this Act until the next rate case or 2007, whichever is sooner.

Questar Gas Competition

Questar Gas is a public utility and currently has no direct competition from other distributors of natural gas for residential and commercial customers. It has historically enjoyed a favorable price comparison with other energy sources used by residential and commercial customers except coal and occasionally fuel oil. It provides transportation service to industrial customers that can buy volumes of gas directly from others. Questar Gas earns lower margins on this transportation service than firm-sales service and could lose customers to Kern River.

Corporate and Other Operations

Historically, Questar's Other Operations included information-technology and communication services; web-hosting and data centers (Consonus); commercial real-estate management; and wellhead gas analysis and automation, field compression and engine maintenance (Energy Services). Questar reorganized these activities in 2004 and 2005 to refocus attention on its primary business activities and reduce costs. Questar has no plans to enlarge the scope of these activities. The majority of information-technology employees and assets were transferred to the separate business segments, and the assets of Consonus were sold. The scope of commercial real estate activities was significantly reduced. Energy Services focuses on wellhead automation and gas analysis.

Environmental Matters

A discussion of Questar s environmental matters is included in Item 3. Legal Proceedings of Part I in this Annual Report.

Employees

At January 1, 2006, the Company had 2,105 employees, including 601 in Market Resources, 178 in Questar Pipeline, 1,170 in Questar Gas, and 156 in Corporate and Other Operations.

Executive Officers

The following individuals are serving as executive officers of the Company:

Primary Positions Held with the Company

and Affiliates, Other Business Experience

Name

Keith O. Rattie

52

Chairman (2003); President (2001); Chief Executive Officer (2002); Director (2001); Chief Operating Officer (2001 to 2002); Director, Questar affiliates (2001). Prior to coming to Questar, Mr. Rattie served successively as Vice President and Senior Vice President of the Coastal Corporation (1996 to 2001).

Charles B. Stanley

47

Executive Vice President, Director Questar (2002); President, Chief Executive Officer and Director, Market Resources and Market Resources subsidiaries (2002); Senior Vice President, Questar (2002 to 2002); Executive Vice President and Chief Operating Officer, Market Resources and Market Resources subsidiaries (2002 to 2002). Prior to joining Questar, Mr. Stanley was President, Chief Executive Officer and Director, Coastal Gas International Co. (1995 to 2000); President and Chief Executive Officer, El Paso Oil and Gas Canada, Inc. (2000 to January 2002).

Alan K. Allred

55

Executive Vice President, Questar (2003); President and Chief Executive Officer and Director, Questar Regulated Services and Questar Gas (2003); Chief Executive Officer and Director, Questar Pipeline (2003 to 2006); President, Questar Pipeline (2003 to 2005); Executive Vice President and Chief Operating Officer, Questar Regulated Services, Questar Gas and Questar Pipeline (2002 to 2003); Senior Vice President, Questar Regulated Services, Questar Gas and Questar Pipeline (2002 to 2002); Vice President, Business Development, Questar Regulated Services, Questar Gas and Questar Pipeline (2000 to 2002); Manager, Regulatory Affairs, Questar Gas and Questar Pipeline (1997 to 2000).

R. Allan Bradley

54

Senior Vice President, Questar (2005); Chief Executive Officer, Questar Pipeline (2006); President, Chief Operating Officer and Director, Questar Pipeline (2005); Prior to joining Questar, Mr. Bradley was Managing Director and founding member, Ventura Energy LLC (2002 to 2004) and Senior Vice President, Coastal Corporation and El Paso Corporation affiliates (1990-2002).

Stephen E. Parks

54

Senior Vice President and Chief Financial Officer (2001); Chief Financial Officer (1996); Treasurer (1984 to 2004); Vice President (1990 to 2001); Vice President, Treasurer and Chief Financial Officer of all affiliates (at various dates beginning 1984); and Director Market Resources subsidiaries (at various dates beginning in 1996).

Thomas C. Jepperson

51

Vice President and General Counsel, Questar (2005); Division Counsel (2000 to 2004); Managing Attorney (1990 to 1999) and Senior Attorney (1988 to 1989) for Market Resources; prior to joining Questar, Mr. Jepperson was a partner of the law firm Nielsen and Senior (Salt Lake City).

Brent L. Adamson

54

Vice President Ethics, Compliance and Audit (2002); Director, Audit (1982 to 2002); Compliance Officer (1995 to 2002).

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

ITEM 1A. RISK FACTORS.

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

The future price of natural gas, oil and NGL is unpredictable. Historically the price of natural gas, oil and NGL has been volatile and is likely to continue to be volatile in the future. Any significant or extended decline in commodity prices would impact the Company s future financial condition, revenues, results of operations, cash flows and rate of growth. Because approximately 90% of Questar s proved reserves at December 31, 2005, was natural gas, the Company is substantially more sensitive to changes in natural gas prices than to changes in oil prices.

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

*

changes in domestic and foreign supply of natural gas, oil and NGL;

*

changes in local, regional, national and global demand for natural gas, oil, and NGL;

*

regional price differences resulting from available pipeline transportation capacity or local demand;

*

the level of imports of, and the price of, foreign natural gas, oil and NGL;

*

domestic and global economic conditions;

*

domestic political developments;

*

weather conditions;

*

domestic and foreign government regulations and taxes;

*

political instability or armed conflict in oil and natural gas producing regions;

*

the price, availability and acceptance of alternative fuels;

*

U.S. storage levels of natural gas, oil, and NGL.

Questar uses derivative instruments to manage exposure to uncertain prices. Questar uses financial contracts to hedge exposure to volatile natural gas, oil, and NGL prices and to protect cash flow, returns on capital, net income and credit ratings from downward commodity price movements. To the extent the Company hedges commodity price exposure, it forgoes the benefits otherwise experienced if commodity prices increase. Questar believes its regulated businesses interstate natural gas transportation and retail gas distribution and its Wexpro subsidiary generate revenues that are not significantly sensitive to short-term fluctuations in commodity prices.

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

The Company may not be able to economically find and develop new reserves. The Company s profitability depends not only on prevailing prices for natural gas, oil and NGL, but also its ability to find, develop and acquire gas and oil reserves that are economically recoverable. Substantial capital expenditures are required to find, develop and acquire gas and oil reserves to replace those depleted by production.

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

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

Questar faces many operating risks to develop and produce its reserves. Drilling is a high-risk activity. Operating risks include: fire, explosions and blow-outs; unexpected drilling conditions such as abnormally pressured formations; abandonment costs; pipe, cement or casing failures; environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine or well fluids (including groundwater contamination). The Company could incur substantial losses as a result of injury or loss of life; pollution or other environmental damage; damage to or destruction of property and equipment; regulatory investigation; fines or curtailment of operations; or attorney s fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in the oil and gas industry, the Company maintains insurance against some, but not all, of these potential risks and losses. Questar can not assure that insurance will be adequate to cover these losses or liabilities. Losses and liabilities arising from uninsured or underinsured events could have an adverse effect on the Company s financial condition and operations.

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

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

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

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

Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to gas and oil operations on Native American tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition each Native American tribe is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Finally, lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. One or more of these factors may increase the Company s costs of doing business on Native American tribal lands and have an impact on the viability of its gas, oil and transportation operations on such lands.

Both Questar Pipeline and Questar Gas incur significant costs to comply with federal pipeline-safety regulations. Questar may also be affected by possible future regulations requiring the tracking, reporting and reduction of greenhouse-gas emissions.

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

State agencies regulate the distribution of natural gas. Questar Gas natural gas-distribution business is regulated by the PSCU and the PSCW. These commissions set rates for distribution services and establish policies and procedures for services, accounting, purchase, sale and other activities. PSCU and PSCW policies may adversely affect Questar Gas profitability.

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Questar E&P and Wexpro

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, 2005. The estimates were collectively prepared by Ryder Scott Company, Netherland, Sewell & Associates, Inc. and H. J. Gruy and Associates, Inc., independent reservoir-engineering consultants. Questar E&P does not have any long-term supply contracts with foreign governments or reserves of equity investees or of subsidiaries with a significant minority interest. All reported reserves are located in the United States.

Estimated proved reserves	
Natural gas (Bcf)	1,324.8
Oil and NGL (MMbbl)	25.9
Total proved reserves (Bcfe)	1,480.4
Proved developed reserves (Bcfe)	920.5
Estimated future net revenues before future income taxes (in thousands) (1)	$8,599,579
Standardized measure of discounted net cash flows (in thousands) (2)	$2,707,072

(1)

Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, using average year-end 2005 prices of $7.80 per Mcf for natural gas and $56.47 per bbl for oil and NGL combined, net of estimated production and development costs (but excluding the effects of general and administrative expenses; debt service; depreciation, depletion and amortization; and income tax expense).

(2)

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

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

Questar E&P s reserve statistics for the years ended December 31, 2003 through 2005, are summarized below:

Proved Gas and Oil Reserves (Bcfe)*

Year	Year-End Reserves	Annual Production	Reserve Life (Years)
2003	1,158.7	92.8	12.5
2004	1,434.0	103.5	13.9
2005	1,480.4	114.2	13.0

*Does not include cost-of-service reserves managed, developed and produced by Wexpro for Questar Gas.

In 2005 gas and oil reserves increased 3%, after production and sales of producing properties, to 1,480.4 Bcfe versus a 24% increase in 2004 to 1,434.0 Bcfe. Questar E&P s production replacement ratio was 141% in 2005 and 366% in 2004. Net reserve additions, revisions, purchases and sales in place totaled 160.6 Bcfe in 2005 and 378.8 Bcfe in 2004. Questar E&P s five-year average finding cost of proved reserves per Mcfe was $1.08, $0.83 and $0.84 in 2005, 2004 and 2003, respectively.

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 s performance, but may not be directly comparable with similar information disclosed by other gas and oil companies.

Questar E&P s proved reserves by major operating areas at December 31, 2005 and 2004 follow:

	2005		2004	
	(Bcfe)	(% of total)	(Bcfe)	(% of total)
Pinedale Anticline	780.0	53%	737.9	51%
Uinta Basin	254.9	17%	272.4	19%
Rockies Legacy	144.4	10%	137.2	10%
Rocky Mountains Total	1,179.3	80%	1,147.5	80%
Midcontinent	301.1	20%	286.5	20%
Questar E&P Total	1,480.4	100%	1,434.0	100%

Reserves Cost-of-Service. The following table sets forth Questar Gas s estimated cost-of-service proved natural gas reserves, which are managed, developed and produced by Wexpro under the terms of the settlement agreement; and Wexpro s proved oil reserve, the estimates were made by Wexpro's reservoir engineers as of December 31, 2005. All reported reserves are located in the United States.

Estimated cost-of-service proved reserves	
Natural gas (Bcf)	497.3

Oil (MMbbl)	3.9
Total proved reserves (Bcfe)	520.5
Proved developed reserves (Bcfe)	425.2

The gas reserves operated by Wexpro are delivered to Questar Gas at cost of service. Net income from oil properties remaining after recovery of expenses and Wexpro s contractual return on investment under the settlement agreement is divided between Wexpro and Questar Gas. Therefore, SEC guidelines with respect to standard economic assumptions are not applicable. The SEC anticipated such potential difficulty and provides that companies may give appropriate recognition to differences arising because of the effect of the ratemaking process. Accordingly, Wexpro 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 17 of the consolidated financial statements included in Item 8 in Part II of this Annual Report for additional information pertaining to both Questar E&P s proved reserves and the Company s cost-of-service reserves as of the end of each of the last three years.

In addition to this filing, Questar E&P and Wexpro will each file estimated reserves as of December 31, 2005, 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 NGL produced, and the production cost per Mcfe for the years ended December 31, 2005, 2004 and 2003, respectively. 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.

	Year Ended December 31,		
	2005	2004	2003
Questar E&P			
Volumes produced and sold			
Gas (Bcf)	100.0	89.8	78.8
Oil and NGL (MMbbl)	2.4	2.3	2.3
Average realized price (including hedges)			
Gas (per Mcf)	$ 5.18	$ 4.18	$ 3.62

Oil and NGL (per bbl)	41.54	30.97	23.39
Production costs (per Mcfe)			
Lease operating expense	$ 0.54	$ 0.50	$ 0.49
Production taxes	0.60	0.46	0.34
Production costs	$ 1.14	$ 0.96	$ 0.83

Cost-of Service (Wexpro-managed)			
Volumes produced			
Gas (Bcf)	40.0	38.8	40.1
Oil and NGL (MMbbl)	0.4	0.4	0.4

Productive Wells. The following table summarizes Market Resources' productive wells (including the cost-of-service wells managed by Wexpro) as of December 31, 2005. All of these wells are located in the United States.

	Gas	Oil	Total
Productive Wells			
Gross	4,215.0	950.0	5,165.0
Net	1,953.9	450.1	2,404.0

Although many Market Resources wells produce both gas and oil, a well is categorized as either a gas or an oil well based upon the ratio of gas to oil produced. Each gross well completed in more than one producing zone is counted as a single well. At the end of 2005, there were 90 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, 2005. Undeveloped Acreage includes leasehold interests that already may have been classified as containing proved undeveloped reserves; and unleased mineral-interest acreage owned by the company. Excluded from the table is acreage in which Market Resources' interest is limited to royalty, overriding-royalty and other similar interests. All leasehold acres are located in the U.S.

Leasehold Acreage December 31, 2005

	Developed (1)		Undeveloped (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arizona	480	450				

480

450

Arkansas

32,049

10,310

3

1

32,052

10,311

California

25

2

1,293

192

1,318

194

Colorado

166,885

120,695

194,147

103,303

361,032

223,998

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

12,634

11,397

1,246

1,126

13,880

12,523

Michigan

89

8

6,240

1,262

6,329

1,270

Minnesota

313

104

313

104

Mississippi

2,904

1,922

965

399

3,869

2,321

Montana

20,149

8,535

301,379

53,279

321,528

61,814

Nevada

320

280

680

543

1,000

823

New Mexico

78,073

54,288

38,462

17,690

116,535

71,978

North Dakota

4,634

546

146,364

21,781

150,998

22,327

Ohio

202

43

202

43

Oklahoma

1,502,162

267,650

83,081

49,927

1,585,243

317,577

Oregon

43,869

7,671

43,869

7,671

South Dakota

204,398

107,829

204,398

107,829

Texas

144,467

60,037

57,651

43,799

202,118

103,836

Utah

103,045

85,671

226,299

109,665

329,344

195,336

Washington

26,631

10,149

26,631

10,149

West Virginia

969

115

969

115

Wyoming

237,278

152,713

403,661

259,524

640,939

412,237

Total

2,336,157

787,605

1,831,839

814,543

4,167,996

1,602,148

(1)

Developed acreage is acreage spaced or assignable to productive wells.

(2)

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

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

Leaseholds Expiring (in Acres)	Acres Expiring	
	Gross	Net
12 Months Ending December 31,		

2006	106,580	73,942
2007	72,432	55,107
2008	65,767	44,257
2009	26,260	22,302
2010 and later	188,780	155,026

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

	Year Ended December 31,					
	Productive			Dry		
	2005	2004	2003	2005	2004	2003
Net Wells Completed						
-Exploratory	6.1	4.7	3.7	1.5		0.2
-Development	165.2	156.0	132.3	7.4	6.6	9.6
Gross Wells Completed						
-Exploratory	9	9	10	4		2
-Development	370	322	282	15	13	19

Gas Management

Gas Management owns 1,381 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 424 MMcf of unprocessed natural gas per day.

Energy Trading

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

Questar Pipeline

Questar Pipeline has a maximum capacity of 3,399 Mdth per day and firm-capacity commitments of 1,920 Mdth per day. Questar Pipeline's transmission system includes 2,499 miles of transmission lines that interconnect with other pipelines. Its core system includes two segments, often referred to as the northern system and southern system. The northern system extends from northwestern Colorado through southwestern Wyoming into northern Utah, while the southern system extends from western Colorado to Goshen, Utah. The transmission mileage includes lines at storage fields and tap lines used to serve Questar Gas, the 488 miles of the Southern Trails system in service that is owned by a subsidiary, and the 88 miles of Overthrust Pipeline that is owned by a subsidiary. The maximum-daily-capacity figures included above for Southern Trails and Overthrust are 88 Mdth and 1,119 Mdth, respectively. Questar Pipeline's system ranges in size from lines that are less than four inches in diameter to the Overthrust line that is 36 inches in diameter. Southern Trails also owns 210 miles of pipeline comprising the California segment of the Southern Trails system, although this segment has not been placed in service. Questar Pipeline has major compression sites, including a complex near Rock Springs, Wyoming, that compress gas volumes from the transmission system for delivery to other pipelines, including systems that move gas volumes east.

Questar Pipeline also owns the Clay Basin storage facility in northeastern Utah, that has a certificated capacity of 117.5 Bcf, including 53.5 Bcf of working gas, and several smaller storage aquifers in northeastern Utah and western Wyoming. Through a subsidiary, Questar Pipeline owns a processing plant in Price, Utah, and related gathering lines.

Questar Gas

Questar Gas distributes gas to customers in the major populated area of Utah, commonly referred to as the Wasatch Front, including the metropolitan Salt Lake area, Provo, Park City, Ogden, and Logan. It also serves customers throughout the state, including the cities of Price, Roosevelt, Vernal, Moab, Monticello, Fillmore, Cedar City and St. George. Questar Gas supplies natural gas to the southwestern Wyoming communities of Rock Springs, Green River, Evanston, Kemmerer and Diamondville and the southeastern Idaho community of Preston. To supply these communities Questar Gas owns and operates distribution systems and has a total of 24,709 miles of street mains, service lines and interconnecting pipelines. Questar Gas has a major operations center in Salt Lake City, Utah, and has operations centers, field offices and service-center facilities through other parts of its service area.

ITEM 3. LEGAL PROCEEDINGS.

Questar is involved in a variety of pending legal disputes involving commercial litigation arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact on Questar cannot be predicted with certainty, management believes that the outcome of these cases will not have a material adverse effect on financial position, operating results or liquidity.

Grynberg. Questar affiliates are involved in various pending lawsuits filed by Jack Grynberg, an independent producer. The only active 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 motions in Wyoming's federal district court. The cases involve allegations of industry-wide mismeasurement of natural gas quantities on which royalty payments are due the federal government

The defendants filed a motion contending that the court has no jurisdiction over the case because Grynberg cannot satisfy the statutory requirements for jurisdiction. The defendants argued Grynberg s allegations were publicly disclosed prior to the filing of his complaint and Grynberg is not the original source of the information on which the allegations are based. The Special Master appointed in the case issued a Report and Recommendation to the district court recommending dismissal of the Questar defendants, except for one small entity acquired by Questar Gas after these cases were filed. The district court heard arguments on whether to adopt the Special Master s Report on December 9, 2005. The district court has not issued a decision. Management is unable to determine a reasonable range of loss, if any, related to this matter.

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

Beaver Gas Pipeline System. On April 8, 2005, Kaiser-Francis appealed the trial judge s order granting 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.). Kaiser-Francis was a co-defendant of Questar E&P 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 which is no longer owned by Questar. 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, plus interest. As part of the settlement, Kaiser-Francis and the plaintiff class agreed to entry of a superseding judgment purporting to vacate the punitive damages award against Kaiser-Francis after the Oklahoma Supreme Court had affirmed that award and issued its mandate. Questar E&P and Anadarko have appealed the entry of the superseding judgment to the Oklahoma Supreme Court.

Kaiser-Francis current lawsuit claims 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 to commit fraud and was therefore barred by a doctrine similar to unclean hands from seeking indemnity for the judgment. On appeal, Kaiser-Francis contends that it should be allowed to amend its petition to argue that the superseding judgment shields it from the jury s findings of wrongdoing. In dismissing the case, the trial judge found that the superseding judgment made no difference.

Consonus Cases. Consonus, its parent company (Questar InfoComm) and certain named officers and directors of Consonus were named as defendants in a lawsuit, *Melnyk v. Consonus, Inc.*, Case No. 2:03-CV-00528DB, pending in a federal district court. The plaintiffs are former minority shareholders who include a former officer and a former director and officer. They claim that the majority shareholders breached their fiduciary duties to minority shareholders by wasting assets and engaging in related-party transactions to the detriment of minority shareholders. Plaintiffs allege that they received an inadequate price for their shares in a statutory merger that occurred in mid-2003. A federal district judge, by an order dated January 26, 2006, dismissed this action with prejudice finding that plaintiffs claims were without merit. The case is pending appeal before the Tenth Circuit Court of Appeals. Questar has sold the Consonus assets.

Environmental Matters.

Questar Pipeline received a Notice of Violation from the Colorado Department of Public Health and Environment, Air Pollution Control Division (APCD) dated February 3, 2005, concerning its operation of a tank battery in Rio Blanco County, Colorado. Specifically, the Colorado agency alleged that Questar Pipeline violated applicable environmental regulations by failing to obtain the necessary permits and complying with the best available control technology. Questar Pipeline has reached a settlement with APCD to resolve the Notice of Violation by entering into a consent order requiring the payment of $319,000 and undertaking a supplemental environmental project with an economic value of $340,000.

In 2004, the Environmental Protection Agency (EPA) issued two separate compliance orders alleging that Gas Management did not comply with regulatory requirements adopted to enforce the federal Clean Air Act. Both orders involved facilities in the Uinta Basin of eastern Utah that were purchased by Questar E&P in mid-2001. Gas Management 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. Potential regulatory violations associated with the timeliness of permit filings for other Gas Management facilities in the Uinta Basin have now been added to the civil penalty discussions with the EPA. These potential violations may yield additional civil penalties of an unknown amount.

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

The Company did not submit any matters to a vote of stockholders during the last quarter of 2005.

PART II

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

Information concerning the market for the common equity of the Company and the dividends paid on such stock is located in Note 16 to the consolidated financial statements included in Item 8 in Part II of this Annual Report. As of February 1, 2006, Questar had 9,798 shareholders of record.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities.

The following table sets forth the Company s purchases of common stock registered under Section 12 of the Exchange Act that occurred during the quarter ended December 31, 2005.

	Total Number of Shares Purchased*	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet Be Purchased Under the Plans
October 1, 2005 to October 31, 2005	2,271	$78.79	—	—
November 1, 2005 to November 30, 2005	10,205	78.27	—	—
December 1, 2005 to December 31, 2005	4,001	76.37	—	—
Total	16,477	$77.88	—	—

*The numbers include shares purchased in conjunction with tax-payment elections under the Company s Long-term Stock Incentive Plan. They exclude any fractional shares purchased from terminating participants in Questar s Dividend Reinvestment and Stock Purchase Plan and any shares of restricted stock forfeited when failing to satisfy vesting conditions.

ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(in thousands, except per-share amounts)				
Revenues	$2,724,888	$1,901,431	$1,463,188	$1,200,667	$1,439,350
Operating expenses					
Cost of natural gas and other products sold	1,371,327	821,833	527,366	391,438	675,011
Operating and maintenance	262,778	213,573	205,011	179,821	159,145
General and administrative	123,055	114,228	94,330	108,800	111,210
Production and other taxes	120,227	90,948	70,681	44,192	55,985
Depreciation, depletion and amortization	250,303	216,175	192,382	184,952	151,735
Impairment of California segment of					
Southern Trails Pipeline	16,000				
Rate-refund obligation		4,090	24,939		
Other expenses	19,469	24,997	8,649	17,269	12,157
Total operating expenses	2,163,159	1,485,844	1,123,358	926,472	1,165,243
Operating income	561,729	415,587	339,830	274,195	274,107
Interest and other income	13,702	6,598	7,657	57,168	37,023
Income from unconsolidated affiliates	7,468	5,125	5,008	11,777	159
Interest expense	(69,295)	(68,429)	(70,736)	(81,121)	(64,833)
Income taxes	(187,923)	(129,580)	(102,563)	(91,126)	(88,270)
Income before accounting changes	325,681	229,301	179,196	170,893	158,186
Cumulative effects of accounting changes			(5,580)	(15,297)	
Net income	$ 325,681	$ 229,301	$ 173,616	$ 155,596	$ 158,186
Basic earnings per common share					
Income before accounting changes	$3.84	$2.74	$2.17	$2.09	$1.95
Cumulative effect of accounting changes			(0.07)	(0.19)	
Net income	$3.84	$2.74	$2.10	$1.90	$1.95
Diluted earnings per common share					

Income before accounting change	$3.74	$2.67	$2.13	$2.07	$1.94
Cumulative effect of accounting change			(0.07)	(0.19)	
Net income	$3.74	$2.67	$2.06	$1.88	$1.94
Weighted-average common shares outstanding					
Used in basic calculation	84,791	83,759	82,697	81,782	81,097
Used in diluted calculation	87,134	85,722	84,190	82,573	81,658
Dividends per share	$0.89	$0.85	$0.78	$0.725	$0.705
Book value per common share at Dec. 31,	$18.16	$17.05	$15.15	$13.88	$13.26
Total assets at Dec. 31,	$4,357,073	$3,674,487	$3,334,195	$3,087,788	$3,241,034
Net cash provided from operating activities	698,260	581,814	436,373	464,724	372,674
Capital expenditures	715,886	442,483	325,339	357,800	984,086
Capitalization at Dec. 31,					
Long-term debt, less current portion	$ 983,200	$ 933,195	$ 950,189	$1,145,180	$ 997,423
Common equity	1,549,803	1,439,558	1,261,265	1,138,761	1,080,781
Total capitalization	$2,533,003	$2,372,753	$2,211,454	$2,283,941	$2,078,204

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

SUMMARY

Questar reported net income of $325.7 million, or $3.74 per diluted share, in 2005 compared to $229.3 million, or $2.67 for 2004 and $173.6 million or $2.06 in 2003. Net income in 2003 was reduced by $5.6 million, or $0.07 per share, due to the cumulative effect of implementing SFAS 143, a new accounting rule governing the treatment of retirement costs of long-lived assets. Following is a comparison of net income by lines of business:

	Year Ended December 31,			Change	Change
	2005	2004	2003	2005 v. 2004	2004 v. 2003

	(dollars in thousands, except per-share amounts)				
NET INCOME (LOSS)					
Questar E & P	$172,788	$108,158	$70,403	$64,630	$37,755
Wexpro	43,669	35,303	32,642	8,366	2,661
Gas Management	35,699	21,047	13,333	14,652	7,714
Energy Trading	6,081	903	(388)	5,178	1,291
Market Resources total	258,237	165,411	115,990	92,826	49,421
Questar Pipeline	24,406	27,596	30,169	(3,190)	(2,573)
Questar Gas	35,975	31,461	20,182	4,514	11,279
Corporate and other operations	7,063	4,833	7,275	2,230	(2,442)
	$325,681	$229,301	$173,616	$96,380	$55,685
Earnings per common share diluted	$3.74	$2.67	$2.06	$1.07	$0.61

Market Resources net income increased 56% in 2005 compared to 2004 and 43% in 2004 over 2003. Primary factors for the higher income were increases in production, higher realized natural gas, oil and NGL prices, increased gas-gathering and processing volumes and margins, and additions to Wexpro s investment base. The cumulative effect of implementing SFAS 143 reduced Market Resources 2003 earnings by $5.1 million.

Questar Pipeline reported net income of $24.4 million in 2005 compared to $27.6 million in 2004. Increased transportation capacity commitments and higher NGL sales prices drove 6% revenue growth. In 2005, Questar Pipeline recorded a $10.4 million after-tax asset impairment for the California segment of the company s Southern Trails Pipeline. Questar Pipeline earned $27.6 million in 2004 compared with $30.2 million in 2003. The 2004 results were lower by $3.0 million after tax as a result of an order to credit to transportation customers certain revenues from the sale of liquids recovered from gas processing. A more-detailed discussion of the FERC decision follows. The cumulative effect of implementing SFAS 143 reduced Questar Pipeline 2003 net income by $133,000.

Questar Gas net income increased 14% in 2005 versus 2004 and increased 56% in 2004 versus 2003. Higher 2005 revenues resulted from a record addition of 30,330 customers. Questar Gas 2005 net income increased $3.0 million with the PSCU approval of a gas-processing settlement agreement. The 2003 results were negatively impacted by a $15.5 million after-tax charge for refund of disputed gas-processing costs, of which $11.9 million related to periods prior to 2003. The cumulative effect of implementing SFAS 143 reduced Questar Gas 2003 earnings by $334,000.

Net income from corporate and other operations increased $2.2 million in 2005 compared with 2004 because of higher net interest income and income tax benefits. In 2004, a reorganization of information-technology assets shifted activities to other business units resulting in a $2.4 million decline in net income compared with 2003.

RESULTS OF OPERATION

Market Resources

Market Resources operates through four principal subsidiaries. Questar E&P acquires, explores for, develops and produces natural gas, oil, and NGL; Wexpro manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas; Gas Management provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and Energy Trading markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned limited liability company, Clear Creek Storage Company, LLC, owns and operates an underground natural gas-storage reservoir.

Market Resources Consolidated Results

Market Resources net income for 2005 was $258.2 million compared with $165.4 million in 2004, a 56% increase, and $116.0 million in 2003. Operating income increased $148.7 million, or 54%, in the year to year comparison due to higher commodity prices and increased natural gas production at Questar E&P, an increased investment base at Wexpro, and increased NGL volumes coupled with improved gas gathering and processing margins at Gas Management. Following is a summary of Market Resources financial and operating results:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
OPERATING INCOME			
Revenues			
Natural gas sales	$ 517,603	$ 375,220	$285,118
Oil and NGL sales	118,633	86,336	67,020
Cost-of-service gas operations	133,204	116,747	100,997
Energy marketing	902,761	506,565	332,927
Gas gathering, processing and other	155,973	100,413	82,946
Total revenues	1,828,174	1,185,281	869,008
Operating expenses			
Energy purchases	888,253	499,726	327,401
Operating and maintenance	158,525	113,772	101,642
Production and other taxes	102,200	73,243	53,343
General and administrative	54,584	49,607	44,113
Depreciation, depletion and amortization	173,770	142,688	121,316
Exploration	11,538	9,239	4,498

Abandonment and impairment of gas, oil and other related properties	7,931	15,758	4,151
Wexpro Agreement oil-income sharing	6,139	4,702	2,199
Total operating expenses	1,402,940	908,735	658,663
Operating income	$ 425,234	$ 276,546	$210,345
OPERATING STATISTICS			
Questar E&P production volumes			
Natural gas (MMcf)	99,959	89,801	78,811
Oil and natural gas liquids (Mbbl)	2,375	2,281	2,324
Total production (Bcfe)	114.2	103.5	92.8
Average daily production (MMcfe)	313	283	254
Average commodity prices, net to the well			
Average realized price (including hedges)			
Natural gas (per Mcf)	$5.18	$4.18	$3.62
Oil and NGL (per bbl)	$41.54	$30.97	$23.39
Average sales price (excluding hedges)			
Natural gas (per Mcf)	$6.92	$5.11	$4.17
Oil and NGL (per bbl)	$51.97	$38.10	$28.47
Wexpro net investment base at December 31, net of depreciation and deferred income taxes (millions)	$206.3	$182.8	$172.8
Natural gas-gathering volumes (thousands of MMBtu)			
For unaffiliated customers	144,978	128,721	114,774
For Questar Gas	43,083	38,997	41,568
For other affiliated customers	68,903	56,958	46,150
Total gathering	256,964	224,676	202,492
Gathering revenue (per MMBtu)	$0.25	$0.22	$0.20
Natural gas and oil-marketing volumes (Mdthe)			
For unaffiliated customers	118,499	91,188	76,352
For affiliated customers	91,751	82,526	73,245
Total marketing	210,250	173,714	149,597

Questar E&P

Questar E&P net income increased 60% to $172.8 million in 2005 compared with $108.2 million in 2004 and $70.4 million in 2003. The increases were driven by a combination of higher realized natural gas, oil and NGL prices and increased gas, oil and NGL production volumes.

Questar E&P s production increased to 114.2 Bcfe in 2005, a 10% increase compared to the year-earlier period. Natural gas is Questar E&P s primary focus. On an energy-equivalent basis, natural gas comprised approximately 88% of Questar E&P s production for 2005. A comparison of energy equivalent production by region is shown in the following table:

	Year Ended December 31,		
	2005	2004	2003
	(in Bcfe)		
Pinedale Anticline	33.2	23.5	15.2
Uinta Basin	25.6	24.8	29.0
Rockies Legacy	16.7	18.0	16.7
Rocky Mountain total	75.5	66.3	60.9
Midcontinent	38.7	37.2	31.9
Total Questar E&P production	114.2	103.5	92.8

Questar E&P production from the Pinedale Anticline in western Wyoming increased 41%

In 2005 and comprised 29% of Questar E&P total production for the year. Questar E&P completed 40 new wells at Pinedale during 2005.

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

Production from Questar E&P s Rockies Legacy properties in 2005 was 16.7 Bcfe compared to 18.0 Bcfe during the 2004 period, a 7% decrease. Legacy properties include all of Questar E&P s Rocky Mountain producing properties other than Pinedale and the Uinta Basin. Production during the 2005 period was negatively impacted by normal field decline, seasonal restrictions that limit access to leases and wells during the winter months, payout of a high-volume well that reduced the company s working interest and mechanical problems that delayed completion of a new well in the Vermillion Basin.

Midcontinent production was 38.7 Bcfe in 2005 compared to 37.2 Bcfe for the same period of 2004, a 4% increase.

The company continued one-rig-development programs in both the Hartshorne coalbed-methane development project in the Arkoma Basin of eastern Oklahoma and the ongoing infill-development drilling on the Elm Grove properties in northwest Louisiana.

Questar E&P also benefited from higher realized prices for natural gas, oil and NGL. In 2005 the weighted average realized natural gas price for Questar E&P (including the effects of hedging) was $5.18 per Mcf compared to $4.18 per Mcf in 2004, a 24% increase. Realized oil and NGL prices for 2005 averaged $41.54 per bbl compared with $30.97 per bbl during the prior year period, a 34% increase. A comparison of average realized prices by region, including hedges, is shown in the following table:

	Year Ended December 31,		
	2005	2004	2003
Natural gas (per Mcf)			
Rocky Mountains	$5.01	$3.95	$3.27
Midcontinent	5.49	4.57	4.26
Volume-weighted average	5.18	4.18	3.62
Oil and NGL (per bbl)			
Rocky Mountains	$42.08	$30.10	$21.95
Midcontinent	40.25	32.98	27.04
Volume-weighted average	41.54	30.97	23.39

Approximately 83% of Questar E&P s gas production in 2005 was hedged or pre-sold compared to 76% in 2004. Hedging reduced gas revenues $173.9 million in 2005 and $83.9 million in 2004. Questar E&P also hedged or pre-sold approximately 70% of its 2005 oil production and 66% of its 2004 production. Oil hedges reduced revenues $24.8 million in 2005 and $16.3 million in 2004.

Questar may hedge up to 100 percent of its forecasted production from proved reserves to lock in acceptable returns on invested capital and to protect cash flow and earnings from a decline in commodity prices. During 2005, Questar E&P continued to take advantage of high natural gas and oil prices to add to hedge additional production in 2006, 2007 and 2008. Natural gas and oil hedges as of December 31, 2005, are summarized in Item 7A of Part I of this Annual Report.

Questar E&P s controllable production cost structure per unit of production (the sum of depreciation, depletion and amortization expense, lease operating expense, general and administrative expense and allocated interest expense) increased 9% to $2.23 per Mcfe in 2005 versus $2.05 per Mcfe in 2004 and $1.99 per Mcfe in 2003. Questar E&P s controllable production cost structure is summarized in the following table:

	Year Ended December 31,		
	2005	2004	2003
		(per Mcfe)	
Depreciation, depletion and amortization	$1.18	$1.04	$0.98
Lease operating expense	0.54	0.50	0.49
General and administrative expense	0.30	0.30	0.29
Allocated interest expense	0.21	0.21	0.23
Total controllable production costs	$2.23	$2.05	$1.99

Depreciation, depletion and amortization expense rose 13% in 2005 to $1.18 per Mcfe due to the ongoing depletion of older, lower-cost reserves, reserve revisions for the company s Uinta Basin properties and higher reserve replacement (finding and development) costs. Higher day rates for rigs and other services in core operating areas, along with sharply higher steel prices, resulted in higher drilling and completion costs.

Production taxes per Mcfe produced were $0.60, $0.46 and $0.34 in 2005, 2004 and 2003, respectively. Increased production taxes were driven by higher gas, oil and NGL sales prices. Most production taxes are based on a fixed percentage of commodity sales prices. Higher lease operating expenses reflect a general increase in well service costs, including costs of contracted services and production-related supplies, increased workover and production enhancement projects and additional production-related costs.

Exploration expense increased $1.9 million in 2005 compared to the 2004. The expense increase was due to increased exploratory seismic acquisition expenditures in the Midcontinent and Uinta Basin.

Questar E&P abandonment and impairment expense declined $5.3 million in 2005 compared to 2004. The 2004 amount included $2.3 million of expense due to a well with collapsed casing.

Pinedale Anticline Drilling Activity

As of December 31, 2005, Market Resources operated and had an interest in 144 producing wells on the Pinedale Anticline compared to 104 and 76 at year-end 2004 and 2003, respectively. In August, 2005, the Wyoming Oil and Gas Conservation Commission (WOGCC) approved 10-acre-density drilling for Lance Pool (combined Lance and Mesaverde formations) wells on about 12,700 acres of Market Resources 18,208 acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the currently estimated productive limits of Market Resources core acreage in the field. On 10-acre density, the company has over 932 potential Lance Pool well locations at Pinedale. Of the 788 locations yet to be drilled, 203 were booked as proved undeveloped at year-end, leaving over 585 locations unbooked. Questar E&P has an average Lance Pool working interest of 59.4% and an average net revenue interest of 47.5% in 873 of the 932 locations. Wexpro has an average Lance Pool working interest of 51.3% in 215 of the 932 locations, resulting in a combined average Lance Pool working interest for Questar E&P and Wexpro of 67.5% in the 932 locations.

On August 19, 2005, Questar E&P reached a total depth of 19,520 feet in the Hilliard Shale at the Stewart Point 15-29 exploratory well. Based on log information and gas shows, Questar E&P identified multiple zones of interest below the Lance Pool at depths from about 16,000 to 19,500 feet, ran casing to total depth and in mid-September commenced hydraulic stimulation and testing. Starting in the lower part of the well, the company pumped three frac stages over a 900 foot interval from 18,541 to 19,434 feet and began flowing the well back to sales on an 18/64 inch choke. During initial flowback, the company measured extrapolated flow rates as high as 10.7 MMcf per day of dry, sweet gas with 10,000 to 12,000 psig flowing casing pressure and an extrapolated rate of about 2,400 barrels per day of frac water. As the flowback continued, the well exhibited steadily declining rates and pressures and, on several occasions, had to be shut in to remove debris plugging the choke. Eventually a combination of very small pieces of shale from the formation, proppant used in the fracs, and chunks of the flow-through frac plugs used to isolate individual stages partially filled the wellbore, blocking the flow of gas to the surface. The vertical extent of the obstruction is currently unknown. . Given the very high formation pressures, specialized equipment (a high-pressure snubbing unit) and experienced personnel are required to attempt to circulate out the obstruction inside the wellbore and either reestablish production from the initial test interval, or isolate that interval and move up hole to test additional zones. The company was not able to secure the right snubbing unit and crew for this operation before cold winter weather would make this operation technically and operationally risky. The resumption of testing of the well will be delayed until the spring of 2006.

Uinta Basin

During 2005, the company drilled or participated in ten horizontal Green River formation oil wells, 54 Wasatch and Upper Mesaverde gas wells, and five deeper Blackhawk and Mancos formation gas wells on its core acreage block.

In December, 2005 Questar E&P completed the Wolf Flat 1P-1-15-19 well, the first well drilled under an Exploration and Development Agreement (EDA) with the Ute Indian Tribe covering 12,557 acres of tribal minerals in the southern Uinta Basin. Questar E&P has a 50% working interest in the Wolf Flat well. The company also completed acquisition of a 2-D seismic survey covering a portion of the EDA lands and exercised its option to acquire leases on all of the EDA lands. The Ute Indian Tribe has the option to participate in the first well drilled in each section with up to a 50% working interest. On December 31, 2005, the company s second 100% working interest test well in the Flat Rock prospect located one mile north of the Wolf Flat well, the FR 1P-36-14-19 well, was waiting on completion.

Rockies Legacy

In the Vermillion Basin on the southwestern Wyoming-northwestern Colorado border, Market Resources continues to evaluate the potential of several formations at depths of 10,000 to 15,000 feet under the company s 143,000 net leasehold acres. As of December 31, 2005, the company had recompleted two older wells, drilled and completed three new wells and was drilling one well, the Canyon Creek 47. The first new well, Alkali Gulch Unit Well No 1, was completed in June 2005 and produced an average of 1.68 MMcf per day from the Baxter, Frontier and Dakota formations during the first 206 days. On December 31, 2005, the well was producing about 1.05 MMcf per day. The second new well, Canyon Creek 41, went to sales on September 21, 2005. During the first 102 days of production, the well averaged about 2.0 MMcf per day from the Baxter and Frontier formations. The well was producing about 1.1 MMcf per day on December 31, 2005. After delays related to mechanical problems, the third new well, Hiawatha Deep Unit No. 5, was completed and turned to sales in mid-November, 2005. During the first 46 days of production, the well averaged 1.2 MMcf per day from the Baxter, Frontier and Dakota formations and was producing about .9 MMcf per day on December 31, 2005. The company currently plans to drill about 12 new wells in the Vermillion Basin during 2006 and has initiated the process with the Bureau of Land Management (BLM) for a new Environmental Impact Statement covering the potential development of the deeper objectives.

Midcontinent

During 2005, the company continued one-rig development programs at both the Hartshorne coalbed-methane project in the Arkoma Basin of eastern Oklahoma and the infill-development drilling project in the Elm Grove properties in northwestern Louisiana. The company drilled or participated in 38 new Hartshorne wells in 2005. In the Elm Grove area, the company drilled or participated in 31 new wells in 2005 and estimates that it has a remaining inventory of about 108 locations.

<u>Wexpro</u>

Wexpro s 2005 net income was $43.7 million compared with $35.3 million in 2004 and $32.6 million in 2003. Wexpro develops and produces gas reserves on behalf of affiliate Questar Gas. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19% on its investment in commercial wells and related facilities adjusted for working capital and reduced for deferred income taxes and depreciation (investment base). Wexpro invested $57.8 million, boosting its investment base 13% to $206.3 million at December 31, 2005, up $23.5 million over the year earlier. Wexpro s 2005 net income also benefited from 35% higher realized oil and NGL prices.

<u>Gas Management</u>

Gas Management net income increased 70% to $35.7 million in 2005 from $21.0 million in 2004 and $13.3 million in 2003. Gross keep-whole processing margins (revenue from the sale of extracted NGLs less the cost of natural gas to replace the Btu-equivalent of extracted NGL volumes) grew 22% from $14.2 million in 2004 to $17.4 million in 2005. The first quarter 2005 acquisition of a gas plant in western Wyoming drove a 59% increase in extracted NGL volumes in 2005 versus the year earlier. Gathering volumes increased 32.3 million MMBtu to 257.0 million MMBtu in 2005 due primarily to expanding Pinedale production and new projects serving third parties in the Uinta Basin.

To reduce processing margin risk, Gas Management has restructured a number of its processing agreements with producers from keep-whole contracts to fee-based contracts. (A keep-whole contract protects producers from frac spread risk, while fee-based contracts eliminate commodity price risk for the plant owner.) To further reduce margin volatility associated with keep-whole contracts, Gas Management began managing NGL price risk in 2004 by using forward-sales contracts. In 2005 keep-whole contracts benefited from a 19% increase in NGL sales prices versus the prior-year. Fee-based contracts benefited from a $0.02 increase in the rate charged per MMBtu processed in 2005. Forward sales contracts decreased NGL revenues by $1.0 million in 2005.

Earnings before tax from Gas Management s 50% interest in Rendezvous increased to $7.2 million in 2005 versus $5.0 million for 2004, a 45% increase. Earnings growth in Rendezvous was driven by increased gathering volumes. Rendezvous provides gas gathering services for the Pinedale and Jonah producing areas. Gas Management continues to invest in additional gas gathering and processing and liquids-handling facilities to serve growing equity and third-party production in its core areas of the Pinedale and Jonah fields in western Wyoming and the Uinta Basin in eastern Utah.

During the first quarter of 2005, Gas Management acquired a cryogenic gas processing facility located approximately 13 miles south of Gas Management s Blacks Fork plant, adding approximately 60 MMcf per day of raw gas processing and NGL extraction capacity at its western Wyoming hub. The plant has been connected to the Blacks Fork/Granger complex to significantly enhance processing and blending capacity for Pinedale, Jonah and other western Wyoming producers served by Gas Management and Rendezvous.

Gas Management completed its condensate and produced-water gathering and transportation facilities on Market Resources Pinedale Anticline leasehold in November 2005 in time to satisfy BLM conditions for expanded winter access. These new facilities will eliminate over 25,500 tanker-truck trips per year at peak production from Market Resources operated acreage and the related air emissions, dust, noise, visual and traffic impacts.

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

Energy Trading

Energy Trading s net income for 2005 was $6.0 million compared to $0.9 million in 2004 and a loss of $0.4 million in 2003. Gross margins for gas and oil marketing (gross revenues less costs for gas and oil purchases, transportation and gas storage) increased to $14.5 million in 2005 versus $6.8 million a year ago, a 113% increase. The increase in gross margin was due primarily to a 77% higher unit margin and a 21% increase in volumes (includes both equity and third-party) over the same period last year.

Questar Pipeline

Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage and non-jurisdictional processing and gathering services. Following is a summary of Questar Pipeline s financial and operating results:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
OPERATING INCOME			
Revenues			
Transportation	$108,169	$105,464	$103,579
Storage	37,389	37,690	37,616
Carbon-dioxide processing	5,618	7,348	7,281
Liquid revenues and other	14,806	5,977	8,362
Total revenues	165,982	156,479	156,838
Operating expenses			
Operating, maintenance, general and administrative	55,906	55,654	53,249
Depreciation and amortization	29,424	28,235	26,141
Impairment of the California segment of Southern Trails Pipeline	16,000		
Other taxes	5,764	6,557	6,352
Operating expenses	107,094	90,446	85,742
Operating income	$ 58,888	$ 66,033	$ 71,096
OPERATING STATISTICS			
Natural gas-transportation volumes (Mdth)			
For unaffiliated customers	259,290	220,514	251,665
For Questar Gas	116,279	116,454	105,720
For other affiliated customers	25,706	18,803	26,224
Total transportation	401,275	355,771	383,609
Transportation revenue (per dth)	$0.27	$0.30	$0.27
Firm daily transportation demand at December 31, (Mdth)	1,920	1,643	1,655

Questar Pipeline s net income was $24.4 million in 2005 compared with $27.6 million in 2004 and $30.2 million in 2003. The 2005 results were reduced by $10.4 million after tax for an impairment of the California segment of Southern Trails. Revenues increased in 2005 due to new transportation contracts and settlement of a liquids revenue sharing dispute with customers. See Note 2 to the consolidated financial statements included in Item 8 of Part II in this

Annual Report for a discussion of the settlement.

Revenues

Gas transportation volumes increased 2005 over the prior year due to new transportation contracts. Following is a summary of major changes in Questar Pipeline s revenues for 2005 compared with 2004 and 2004 compared with 2003:

#

	Change in Revenues	
	2004 to 2005	2003 to 2004
	(in thousands)	
Transportation revenues		
New transportation contracts	$ 4,700	$ 4,300
Expiration of transportation contracts	(1,700)	(1,300)
Storage revenues	(300)	100
Changes in interruptible transportation and other	(300)	(1,100)
Carbon-dioxide processing	(1,700)	(100)

Liquid revenues and other		
Change in liquid revenues before credit	5,600	2,500
Credit of liquid revenues	2,400	(4,700)
Other changes	800	(100)
Increase (decrease)	$ 9,500	$ (400)

Questar Pipeline has expanded its transportation system in response to growing regional natural gas production and transportation demand. Questar Pipeline added new transportation contracts in 2004 and 2005 for deliveries to the Kern River pipeline at Goshen, Utah. In the second quarter of 2005, Questar Pipeline began service to an electric generation facility in central Utah.

Questar Pipeline s existing transportation system is nearly fully contracted. As of December 31, 2005, Questar Pipeline had firm-transportation contracts of 1,920 Mdth per day compared with 1,643 Mdth per day as of December 31, 2004. The increase was primarily due to a new contract of 190 Mdth per day to serve an electric generation facility and 102 Mdth per day for an expansion of its southern system. Questar Pipeline began partial service on this expansion in September 2005 and full service in November 2005. Questar Pipeline s firm-transportation contracts had a weighted average remaining life of 10.9 years as of December 31, 2005.

Questar Gas is Questar Pipeline s largest transportation customer with firm transportation contracts for 951 Mdth per day, including 50 Mdth per day for winter-peaking service. Most of these contracts extend through mid 2017.

Questar Pipeline owns and operates the Clay Basin underground gas storage facility, the largest in the region, with working gas capacity of 53.5 Bcf. This facility is 100% subscribed under long-term contracts. In addition to Clay Basin, Questar Pipeline also owns and operates three smaller aquifer gas storage facilities. Questar Pipeline s firm storage contracts had a weighted average remaining life of 8.0 years as of December 31, 2005.

Questar Gas has contracted for 26% of firm-storage capacity at Clay Basin for terms extending from three to 14 years and 100% of the firm-storage capacity at the aquifer facilities for terms extending for 13 years.

Questar Pipeline transportation and storage rates are based on straight-fixed-variable rate design and approved by the FERC. All fixed costs of providing service including depreciation and return on investment are recovered through the demand charge. Fixed costs comprise about 95% of Questar Pipeline costs and are recovered through demand charges. Therefore, Questar Pipeline s earnings are driven primarily by demand revenues from firm shippers. Variable operating costs based on throughput are recovered through volumetric charges. With straight-fixed variable rate design, period-to-period changes in firm-transportation volumes do not have a significant impact on earnings.

See Note 2 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for discussion of Questar Pipeline s fuel-gas reimbursement percentage (FGRP) proceedings.

In addition to the changes in liquid revenues associated with the FGRP proceedings, 2005 liquid revenues increased $5.6 million over 2004 due to higher NGL prices and volumes.

Expenses

Operating, maintenance, general and administrative expenses were flat in 2005 compared with 2004 and increased 5% in 2004 compared with 2003. The increases were primarily due to higher labor and labor overhead costs offset by lower information technology and fuel gas costs. Operating, maintenance, general and administrative expenses per dth transported were $0.139 in 2005 compared with $0.156 in 2004 and $0.139 in 2003. Operating, maintenance, general and administrative expenses include processing and storage costs.

Depreciation expense increased 4% in 2005 over 2004 and 8% in 2004 over 2003 reflecting increased pipeline investment.

Clay Basin Storage

Questar Pipeline conducts periodic pressure tests on its Clay Basin storage facility. Beginning with a test in April 2002, the company noted a discrepancy between the book volumes of cushion gas at Clay Basin and the volumes implied by pressure data. Questar Pipeline retained a reservoir consultant to model the reservoir and determine the size and cause of the discrepancy. The company conducted additional pressure tests in April 2004, October 2004, April 2005 and October 2005 to validate the model.

The reservoir model indicates from 0 to 3.8 Bcf of gas may be missing from Clay Basin, with the most likely amount of 3.2 Bcf. The gas loss is due to a combination of cumulative imprecision inherent in natural gas measurement devices and reservoir heterogeneity that impacts storage reservoir performance. There is no indication that the reservoir is leaking. The Clay Basin reservoir is functioning as expected to meet customer requirements.

Questar Pipeline has proposed to the FERC that the loss of gas be recorded as a reduction of native gas remaining in the reservoir which would not impact Questar Pipeline net income. Alternatively, if the FERC requires Questar Pipeline to adjust recoverable cushion gas, earnings could be reduced by about $3 million after taxes.

Carbon Dioxide Processing Plant

Questar Transportation Services, a subsidiary of Questar Pipeline, owns non-jurisdictional gathering lines and a processing plant near Price, Utah. The plant was built in 1999 to process gas on behalf of Questar Gas. Questar Gas and other parties have contracted for the plant s firm capacity and pay the cost of service for operating the plant.

Regulation

FERC Order No. 2004 requires employees engaged in transportation system operations to function independently from employees of marketing and energy affiliates. In addition a transportation provider must treat all transportation customers on a non-discriminatory basis and must not operate its transportation system to preferentially benefit its marketing or energy affiliates. Questar Pipeline has determined that all Market Resources subsidiaries except Gas Management are marketing or energy affiliates. Questar Gas is not an energy or marketing affiliate.

Questar Pipeline is required to comply with the Pipeline Safety Improvement Act of 2002. This Act and the rules issued by the DOT require interstate pipelines and local distribution companies to implement a 10-year program of risk analysis, pipeline assessment and remedial repair for transportation pipelines located in high-consequence areas such as densely populated locations. Questar Pipeline s plan for complying with the Act was filed with the DOT during 2004. Questar Pipeline estimates that its annual cost to comply with the Act will be approximately $1 million, not including costs of pipeline replacement, if necessary.

See Note 2 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for a discussion of the Fuel Gas Reimbursement Percentage filings with the FERC.

Southern Trails Pipeline

See Note 4 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for discussion of the impairment of the California segment of Southern Trails.

Questar Gas

Questar Gas distributes natural gas in Utah, southwestern Wyoming and southeastern Idaho. Following is a summary of Questar Gas s financial and operating results:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
OPERATING INCOME			
Revenues			
Residential and commercial sales	$867,794	$680,658	$552,773
Industrial sales	40,107	49,094	45,279
Transportation for industrial customers	5,880	6,355	7,108
Other	48,766	28,086	15,835
Total revenues	962,547	764,193	620,995
Cost of natural gas sold	720,173	536,128	394,523
Margin	242,374	228,065	226,472
Operating expenses			
Operating, maintenance, general and administrative	113,086	104,786	100,279
Rate-refund obligation		4,090	24,939
Depreciation and amortization	45,828	41,956	40,126
Other taxes	11,013	9,767	9,743
Total operating expenses	169,927	160,599	175,087
Operating income	$ 72,447	$ 67,466	$ 51,385

OPERATING STATISTICS			
Natural gas volumes (Mdth)			
Residential and commercial sales	96,310	92,975	84,393
Industrial sales	5,681	8,823	9,613
Transportation for industrial customers	31,205	34,278	38,341
Total industrial	36,886	43,101	47,954
Total deliveries	133,196	136,076	132,347
Natural gas revenue (per dth)			
Residential and commercial	$9.01	$7.32	$6.55
Industrial sales	7.06	5.56	4.71
Transportation for industrial customers	0.19	0.19	0.19
System natural gas cost (per dth)	$6.46	$5.20	$4.13
Heating degree days colder (warmer) than normal	(3%)	3%	(7%)
Temperature-adjusted usage per customer (dth)	113.7	114.9	118.9
Customers at December 31,	824,447	794,117	770,494

Questar Gas s net income increased to $36.0 million in 2005 compared with $31.5 million in 2004 and $20.2 million in 2003. The 2003 results were reduced by a $15.5 million after tax charge for refund of disputed gas-processing costs, of which $11.9 million related to periods prior to 2003.

Margin Analysis

Questar Gas s margin (revenues less gas costs) increased $14.3 million in 2005 compared with 2004, and $1.6 million in 2004 compared with 2003. Following is a summary of major changes in Questar Gas s margin for 2005 compared to 2004 and 2004 compared to 2003:

	Change in margin	
	2004 to 2005	2003 to 2004
	(in thousands)	
New customers	$ 6,600	$ 5,100
Change in usage per customer	(1,600)	(6,300)
Interest on past-due receivables	1,200	400
Processing cost recovery	900	
Recovery of gas-cost portion of bad-debt costs	2,100	1,400

Other, including shifting between rate classes	5,100	1,000
Total	$14,300	$ 1,600

Residential and commercial sales volumes increased 4% in 2005 compared with 2004 as increased customers and increased usage per customer offset the impact of warmer weather. At December 31, 2005, Questar Gas was serving 824,447 customers, a 3.8% increase over the prior year. Housing construction in Utah remained strong, driven by population growth and continuing low mortgage-interest rates. Usage per customer, adjusted for normal temperatures, was down 1% in 2005 compared with 2004 and down 3% in 2004 compared with 2003. Over the long term, usage per customer has been decreasing due to more efficient appliances and homes and customer response to higher prices.

Weather, as measured in degree days, was 3% warmer than normal in 2005 compared to 3% colder than normal in 2004 and 7% warmer than normal in 2003. A weather-normalization adjustment on customer bills generally offsets financial impacts of moderate temperature variations.

Industrial deliveries declined 14% in 2005 compared with 2004 and 10% in 2004 compared with 2003 primarily driven by lower power-generation requirements in the current period and customers changing to the residential and commercial rate schedules.

Expenses

Cost of natural gas sold increased 34% in 2005 compared with 2004 and 36% in 2004 compared with 2003 due to increased gas purchase costs and increased volumes. Questar Gas accounts for purchased-gas costs in accordance with procedures authorized by the PSCU and the PSCW. Purchased-gas costs that are different from those provided for in present rates are accumulated and recovered or credited through future rate changes. As of December 31, 2005, Questar Gas had a $39.9 million balance in the purchased-gas adjustment account representing gas costs incurred but not yet recovered from customers. On November 1, 2005, Questar Gas increased Utah rates by 20% to cover higher costs of purchased natural gas. Combined with a 14% increase in June and other changes, customer rates at December 31, 2005 were 42% higher than the prior year. In February 2006, Questar Gas reduced rates by 8% to reflect forecasts of lower gas purchase prices.

Operating, maintenance, general and administrative expenses increased 8% in 2005 compared with 2004 and 4% in 2004 compared with 2003. The increases are due to higher labor and labor overhead costs and bad debt costs.

Depreciation expense increased 9% in 2005 compared with 2004 and 5% in 2004 compared with 2003 due to plant additions, including a customer information system that was placed in service in July 2004 and transfers of information technology assets from affiliates.

Rate-refund Obligation

See Note 2 to the consolidated financial statements included in Item 8 of Part II of this Annual Report for a discussion of the regulatory proceedings involving Questar Gas s processing costs.

Regulation

Questar Gas is subject to the requirements of the Pipeline Safety Improvement Act. Questar Gas estimates that it will cost $4.0 to $5.0 million per year to comply with the act, not including costs of pipeline replacement if necessary. The PSCU has allowed Questar Gas to record a regulatory asset for these incremental operating costs incurred to comply with this Act until the next rate case or 2007, whichever is sooner.

Corporate and Other Operations

Corporate and Other Operations include other services and activities. Revenues include sales to affiliates.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
OPERATING INCOME			
Revenues	$ 19,085	$35,645	$48,113
Operating expenses			
Cost of products sold	5,390	5,892	4,651
Operating and maintenance	704	10,990	20,198
General and administrative	5,300	8,544	10,218
Depreciation and amortization	1,281	3,296	4,799
Other taxes	1,250	1,381	1,243
Total operating expenses	13,925	30,103	41,109
Operating income	$ 5,160	$ 5,542	$ 7,004

Revenues decreased 46%, operating and maintenance decreased 94%, general and administrative expense decreased

38% and depreciation decreased 61% in 2005 compared with 2004 due to the 2004 reorganization of information-technology-related businesses and the May 2005 sale of data-hosting assets. Questar reorganized its information-technology services in June 2004, resulting in a reduction of staff and $0.6 million of severance costs. The remaining information-technology assets and employees were transferred to affiliates. Revenues, operating and maintenances expense, depreciation and amortization decreased in 2004 compared with 2003 also as a result of the discussed reorganizations.

Consolidated Operating Results After Operating Income

Interest and Other Income

Interest and other income was higher in 2005 compared to 2004 as shown in the table below. Questar Gas s return on gas stored underground increased because of higher rates and inventory valuations. The higher earnings also reflect interest received on hedging collateral deposits. Gains from asset sales added $4.7 million before tax in 2005.

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Interest income and other earnings	$ 3,291	$1,919	$4,243
Net gain (loss) from asset sales	4,742	336	(525)
Allowance for other funds used during construction (capitalized finance costs)	678	273	1,125
Return earned on working-gas inventory and purchased-gas-adjustment account	4,991	4,070	2,814
Total	$13,702	$6,598	$7,657

Earnings from unconsolidated affiliates

Gas Management has a 50% interest in Rendezvous, which provides gas-gathering services for the Pinedale and Jonah producing areas of western Wyoming. Gas Management s share of Rendezvous earnings before tax increased to $7.2 million in 2005 compared to $5.0 million in 2004. Rendezvous gathering volumes increased 47% in 2005 compared to 2004.

Interest expense

Interest expense rose in 2005 because the Company increased borrowings to meet hedging collateral calls precipitated by increases in natural gas and oil prices.

Income taxes

The effective combined federal and state income tax rate was 36.6% in 2005, 36.1% in 2004 and 36.4% in 2003.

Cumulative Effect of Accounting Change

On January 1, 2003, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, and recorded a cumulative effect that reduced net income by $5.6 million, or $0.07 per diluted common share.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

Net cash provided from operating activities increased 20% in 2005 compared to 2004 and 33% in 2004 compared to 2003 due to higher net income and noncash adjustments to income.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Net income	$325,681	$229,301	$173,616
Noncash adjustments to net income	373,826	354,117	296,725
Changes in operating assets and liabilities	(1,247)	(1,604)	(33,968)
Net cash provided from operating activities	$698,260	$581,814	$436,373

Investing Activities

Capital spending in 2005 amounted $715.9 million. The details of capital expenditures in 2005 and 2004 and a forecast for 2006 are shown in the table below.

	Year Ended December 31,		
	2006	2005	2004
	Forecast		
		(in thousands)	
Market Resources			
Drilling and other exploration	$ 22,800	$ 51,671	$ 29,229
Development drilling	331,600	355,116	222,455
Wexpro development drilling	62,900	53,652	39,184
Reserve acquisitions		3,497	1,131
Production	15,800	24,817	13,640
Gathering and processing	52,000	96,733	26,979
Storage		545	1,171
General	5,300	2,881	12,040
	490,400	588,912	345,829
Questar Pipeline			
Transmission system	100,700	60,168	27,828
Storage	17,300	3,378	1,971
Southern Trails Pipeline	700	744	52
Gathering and processing	1,000	102	438
General	2,700	1,126	1,826
	122,400	65,518	32,115
Questar Gas			
Distribution system and customer additions	82,100	53,237	53,092
General	17,000	16,920	24,131
	99,100	70,157	77,223
Corporate and Other Operations	800	1,189	2,574
	712,700	725,776	457,741
Capital expenditure accruals		(9,890)	(15,258)
Total capital expenditures	$712,700	$715,886	$442,483

Market Resources

Market Resources expanded Rockies, Uinta Basin and Midcontinent drilling programs and construction of the water and condensate gathering system to serve the Pinedale Anticline represented the majority of the increase in capital expenditures for 2005 compared to 2004. Completion of the water and condensate gathering system in 2005 is the primary reason for the decrease in forecast 2006 capital expenditures.

In 2005 Market Resources increased drilling activity at Pinedale and in the Midcontinent region. During 2005 Market Resources participated in 501 wells (180.2 net), resulting in 171.3 net successful gas and oil wells and 8.9 net dry or abandoned wells. The net drilling-success rate was 95.1% in 2005. There were 103 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.

Questar Pipeline

During 2005, Questar Pipeline completed a new pipeline extension to a power plant in Mona, Utah, and completed a 102 MMdth per day expansion of its southern transportation system.

Questar Gas

During 2005, Questar Gas added 532 miles of main, feeder and service lines to provide service to 30,330 new customers.

Corporate and other operations

Net cash used in investing activities includes proceeds of $13.0 million from the second quarter 2005 sale of Consonus assets.

Financing Activities

Net cash flow provided from operating activities was sufficient to fund net capital expenditures in 2005. In the fourth quarter, the Company repaid $200 million borrowed in the third quarter on Market Resources revolving loan facility. In 2005, Questar Gas borrowed $50 million from a bank under a five-year loan agreement and used the proceeds to repay short-term debt.

Short-term debt amounted to $94.5 million at December 31, 2005, and was comprised of commercial paper with an average interest rate of 4.43%. A year earlier short-term debt amounted to $68.0 million and was comprised of commercial paper with an average interest rate of 2.45%. Questar s commercial paper borrowings are backed by short-term line-of-credit arrangements. The Company had $420 million of short-term lines of credit at December 31, 2005.

Questar consolidated capital structure consisted of 41% combined short- and long-term debt and 59% common shareholders' equity at December 31, 2005 and 2004. Ratings of senior-unsecured debt as of December 31, 2005, were as follows:

	Moody s	Standard & Poor s
Market Resources	Baa3	BBB+
Questar Pipeline	A2	A-
Questar Gas	A2	A-
Questar short-term debt	P2	A2

Standard & Poor s and Moody s ratings were designated as stable.

The Company had negative net working capital at December 31, 2005, because of liabilities associated with out-of-the money energy-hedging derivatives.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, Questar enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2005.

	Payments Due by Year				
	Total	2006	2007-2008	2009-2010	After 2010
			(in millions)		
Long-term debt	$ 983.5		$311.3	$ 92.1	$580.1

Gas-purchase contracts	414.5	$264.7	116.2	33.6	
Transportation contracts	103.4	9.9	19.8	19.3	54.4
Operating leases	33.4	5.2	10.7	9.9	7.6
Total	$1,534.8	$279.8	$458.0	$154.9	$642.1

Critical Accounting Policies, Estimates and Assumptions

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

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.

Questar Gas estimates revenues on a calendar basis even though bills are sent to customers on a cycle basis throughout the month. The company estimates unbilled revenues for the period from the date meters are read to the end of the month, using usage history and weather information. Approximately one-half month of revenues is estimated in any period. The gas costs and other variable costs are recorded on the same basis to ensure proper matching of revenues and expenses.

Questar Gas s tariff provides for monthly adjustments to customer charges to approximate the impact of normal temperatures on nongas revenues. Questar Gas estimates the weather-normalization adjustment for the unbilled revenue each month. The weather-normalization adjustment is evaluated each month and reconciled on an annual basis in the summer to agree with the amount billed to customers.

Rate Regulation

Regulatory agencies establish rates for the storage, transportation, distribution and sale of natural gas. The regulatory agencies also regulate, 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. Questar Gas and Questar Pipeline follow SFAS 71, Accounting for the Effects of Certain Types of Regulation, that requires the recording of regulatory assets and liabilities by companies subject to cost-based regulation. The FERC, PSCU and PSCW have accepted the recording of regulatory assets and liabilities.

Employee Benefit Plans

The Company has pension and post-retirement-benefit plans covering a majority of its employees. The calculation of the Company s expense and liability associated with its benefit plans requires the use of a number of assumptions that the Company deems to be critical. Changes in these assumptions can result in different expenses and liabilities and actual experience can differ from these assumptions.

Independent consultants hired by the Company use actuarial models to calculate estimates of pension and post-retirement benefits expense. The models use key factors such as mortality estimations, liability discount rates, long-term rates of return on investments, rates of compensation increases, amortized gain or loss from investments and medical-cost trend rates. Management makes assumptions based on market indicators and advice from consultants. The Company believes that the liability discount rate and the expected long-term rate of return on benefit plan assets are critical assumptions.

The assumed liability discount rate reflects the current rate at which the pension benefit obligations could effectively be settled. Management considers the rates of return on high-quality, fixed income investments and compares those results with a bond-defeasance technique. The Company discounted its future pension liabilities using rates of 6.50% and 6.75% as of December 31, 2005, and 2004, respectively. A 0.25% decrease in the discount rate increased the Company s 2005 qualified pension annual expense by $1.5 million.

The expected long-term rate of return on benefit plan assets reflects the average rate of earnings expected on funds invested or to be invested to provide for the benefits included in the benefit plan liability. The Company establishes the expected long-term rate of return at the beginning of each fiscal year giving consideration to the benefit plan s investment mix and the historical and forecasted rates of return on these types of securities. The expected long-term rate of return determined by the Company was 8.25% and 8.50% as of January 1, 2005, and 2004, respectively. Benefit plan expense typically increases as the expected long-term rate of return on plan assets decreases. A 0.25%

decrease in the expected long-term rate of return causes a $0.6 million increase in 2005 pension expense.

Recent Accounting Developments

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

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

Questar s 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 Company s Board of Directors. Market Resources may hedge up to 100% of forecast production from proved reserves when prices meet earnings and cash-flow objectives. Market Resources does not enter into derivative arrangements for speculative purposes and does not hedge undeveloped reserves or 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 income. The ineffective portion of hedges was not significant in 2005 and 2004.

As of December 31, 2005, approximately 142.8 Bcf of forecast gas production for 2006, 2007 and 2008 was hedged at an estimated average price of $6.62 per Mcf, net to the well (which reflects assumed adjustments for regional basis, gathering and processing costs and gas quality).

Questar enters into commodity price hedging arrangements with creditworthy counterparties (banks and industry participants) with a variety of credit requirements. Some contracts do not require the Company to post cash collateral, while others allow some amount of credit before requiring deposits of collateral for out-of-the-money hedges. The amount of credit available may vary depending on the credit rating assigned to the Company s debt securities. A substantial increase in the price of natural gas, oil and/or NGL could result in the requirement to deposit large amounts of collateral with counterparties that could seriously impact the Company s cash liquidity. Additionally a downgrade in the Company s credit ratings to sub-investment grade could result in the acceleration of obligations to hedge counterparties. In addition to the counterparty arrangements, Market Resources has a $200 million long-term revolving-credit facility with banks that was not utilized at December 31, 2005.

A summary of Market Resources hedging positions for equity production as of December 31, 2005, 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.

Time Periods	Rocky Mountains	Midcontinent	Total	Rocky Mountains	Midcontinent	Total
					Estimated	
		Gas (in Bcf)			Average price per Mcf, net to the well	
First half of 2006	25.7	11.9	37.6	$5.93	$6.81	$6.21
Second half of 2006	26.1	12.2	38.3	5.93	6.81	6.21
12 months of 2006	51.8	24.1	75.9	5.93	6.81	6.21
First half of 2007	14.7	10.1	24.8	$6.80	$7.82	$7.22
Second half of 2007	14.9	10.3	25.2	6.80	7.82	7.22
12 months of 2007	29.6	20.4	50.0	6.80	7.82	7.22
First half of 2008	5.1	3.3	8.4	$6.36	$7.23	$6.70
Second half of 2008	5.1	3.4	8.5	6.36	7.23	6.70
12 months of 2008	10.2	6.7	16.9	6.36	7.23	6.70

	Oil (in Mbbl)			Estimated Average price per bbl, net to the well		
First half of 2006	615	200	815	$47.77	$59.89	$50.73
Second half of 2006	626	202	828	47.77	59.89	50.73
12 months of 2006	1,241	402	1,643	47.77	59.89	50.73
First half of 2007	453	181	634	$56.01	$57.08	$56.32
Second half of 2007	460	184	644	56.01	57.08	56.32
12 months of 2007	913	365	1,278	56.01	57.08	56.32

Market Resources held gas price hedging contracts covering the price exposure for about 184.4 million MMBtu of gas, 2.9 MMbbl of oil and 10.1 MMgal of NGL as of December 31, 2005. A year earlier Market Resources hedging contracts covered 135.6 million MMBtu of natural gas, 1.1 MMbbl of oil and 3.8 MMgal of NGL. 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, 2004 to December 31, 2005:

	(in thousands)
Net fair value of hedging contracts outstanding at December 31, 2004	($ 67,501)
Contracts realized or otherwise settled	54,845
Increase in prices on futures markets	(123,875)
New contracts since December 31, 2004	(182,590)
Net fair value of hedging contracts outstanding at December 31, 2005	($319,121)

A table of the net fair value of hedging contracts as of December 31, 2005, is shown below. About 69% 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, 2006	($220,077)
Contracts maturing between December 31, 2006, and December 31, 2007	(78,870)
Contracts maturing between December 31, 2007, and December 31, 2008	(20,174)
Net fair value of hedging contracts at December 31, 2005	($319,121)

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

	At December 31, 2005	2004
	(in millions)	
Mark-to-market valuation asset (liability)	($319.1)	($67.5)
Value if market prices decline by 10%	(166.9)	2.5
Value if market prices increase by 10%	(471.4)	(137.5)

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 Company, Nevada Power Company, ONEOK Energy Services Company LP, Coral Energy Resources, LP and Sempra Energy Trading Corp. Sales to these companies accounted for 20% of Market Resources revenues before elimination of intercompany transactions in 2005, and their accounts were current at December 31, 2005.

Questar Pipeline requests credit support, such as letters of credit and cash deposits, from those companies that pose unfavorable credit risks. All companies posing such concerns were current on their accounts at December 31, 2005. Questar Pipeline s largest customers include Questar Gas, PacifiCorp, Colorado Interstate Gas, EOG Resources and Anadarko Petroleum.

Interest Rate Risk

The Company had $983.5 million of fixed-rate long-term debt at December 31, 2005. The fair value of fixed-rate debt is subject to change as interest rates fluctuate. The fair value of Questar's long-term debt amounted to $1.04 billion at December 31, 2005. The Company had $933.5 million of fixed-rate long-term debt at December 31, 2004 with a fair value of $1.03 billion at December 31, 2004. If interest rates declined 10%, fair value would increase to $1.06 billion in 2005 and $1.05 billion in 2004. The fair value calculations do not represent the cost to retire the debt securities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Financial Statements:

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income, three years ended December 31, 2005

Consolidated Balance Sheets at December 31, 2005 and 2004

Consolidated Statements of Common Shareholders' Equity, three years ended December 31, 2005

Consolidated Statements of Cash Flows, three years ended December 31, 2005

Notes Accompanying the Consolidated Financial Statements

Financial Statement Schedules:

Valuation and Qualifying Accounts, for the three years ended December 31, 2005

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Questar Corporation

We have audited the accompanying consolidated balance sheets of Questar Corporation and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders equity, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Questar Corporation and subsidiaries at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 3 to the financial statements, Questar Corporation and subsidiaries adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Questar Corporation s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Salt Lake City, Utah

February 27, 2006

QUESTAR CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2005	2004	2003
	(in thousands, except per share amounts)		
REVENUES			
Market Resources	$1,668,670	$1,053,854	$ 751,502
Questar Pipeline	82,589	67,844	74,981
Questar Gas	956,403	759,486	618,791
Corporate and other operations	17,226	20,247	17,914
TOTAL REVENUES	2,724,888	1,901,431	1,463,188
OPERATING EXPENSES			
Cost of natural gas and other products sold	1,371,327	821,833	527,366
Operating and maintenance	262,778	213,573	205,011
General and administrative	123,055	114,228	94,330
Production and other taxes	120,227	90,948	70,681
Depreciation, depletion and amortization	250,303	216,175	192,382
Impairment of California segment of Southern Trails Pipeline	16,000		
Questar Gas rate-refund obligation		4,090	24,939
Exploration	11,538	9,239	4,498
Abandonment and impairment of gas, oil and other related properties	7,931	15,758	4,151
TOTAL OPERATING EXPENSES	2,163,159	1,485,844	1,123,358
OPERATING INCOME	561,729	415,587	339,830
Interest and other income	13,702	6,598	7,657
Income from unconsolidated affiliates	7,468	5,125	5,008
Interest expense	(69,295)	(68,429)	(70,736)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT	513,604	358,881	281,759
Income taxes	187,923	129,580	102,563
INCOME BEFORE CUMULATIVE EFFECT	325,681	229,301	179,196
Cumulative effect of accounting change for asset-			

retirement obligations, net of income taxes of $3,331			(5,580)
NET INCOME	$ 325,681	$ 229,301	$ 173,616
BASIC EARNINGS PER COMMON SHARE			
Income before cumulative effect	$ 3.84	$ 2.74	$ 2.17
Cumulative effect			(0.07)
Net income	$ 3.84	$ 2.74	$ 2.10
DILUTED EARNINGS PER COMMON SHARE			
Income before cumulative effect	$ 3.74	$ 2.67	$ 2.13
Cumulative effect			(0.07)
Net income	$ 3.74	$ 2.67	$ 2.06
Weighted-average common shares outstanding			
Used in basic calculation	84,791	83,759	82,697
Used in diluted calculation	87,134	85,722	84,190

See notes accompanying the consolidated financial statements

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QUESTAR CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS	December 31,	
	2005	2004
	(in thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ 13,360	$ 3,681
Federal income taxes recoverable	11,274	
Accounts receivable, net	355,810	253,365
Unbilled gas accounts receivable	86,161	59,160
Hedging collateral deposits	5,150	
Fair value of hedging contracts	1,972	9,334
Inventories, at lower of average cost or market		
Gas and oil storage	90,718	66,944
Materials and supplies	34,699	18,487
Prepaid expenses and other	30,110	23,690
Purchased-gas adjustments	39,852	35,853
Deferred income taxes current	86,734	26,013
TOTAL CURRENT ASSETS	755,840	496,527
NET PROPERTY, PLANT AND EQUIPMENT successful efforts method of accounting for gas and oil properties	3,427,542	2,984,592
INVESTMENT IN UNCONSOLIDATED AFFILIATES	30,681	33,229
OTHER ASSETS		
Goodwill	71,260	71,260
Regulatory assets	32,767	34,442
Intangible pension asset	10,780	12,394
Fair value of hedging contracts		1,815
Other noncurrent assets, net	28,203	40,228
TOTAL OTHER ASSETS	143,010	160,139

	$4,357,073	$3,674,487

QUESTAR CORPORATION
LIABILITIES AND SHAREHOLDERS' EQUITY

	December 31, 2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Short-term debt	$ 94,500	$ 68,000
Accounts payable and accrued expenses		
Accounts and other payables	444,382	282,068
Production and other taxes	67,346	43,368
Rate-refund obligation		25,343
Questar Gas customer credit balances	30,829	24,771
Interest	14,468	14,464
Federal income taxes		1,447
Total accounts payable and accrued expenses	557,025	391,461
Fair value of hedging contracts	222,049	64,179
TOTAL CURRENT LIABILITIES	873,574	523,640
LONG-TERM DEBT, less current portion	983,200	933,195
DEFERRED INCOME TAXES	624,187	572,446
ASSET RETIREMENT OBLIGATIONS	78,123	67,288
PENSION LIABILITY	44,634	32,640
POST-RETIREMENT BENEFITS	16,415	15,279
FAIR VALUE OF HEDGING CONTRACTS	99,044	14,471
OTHER LONG-TERM LIABILITIES	88,093	75,970
COMMITMENTS AND CONTINGENCIES Note 12		
COMMON SHAREHOLDERS' EQUITY		
Common stock without par value; 350,000,000 shares authorized; 85,319,837 outstanding at December 31, 2005, and 84,441,340 outstanding at December 31, 2004	383,298	358,017
Retained earnings	1,385,783	1,135,718
Accumulated other comprehensive loss	(219,278)	(54,177)

TOTAL COMMON SHAREHOLDERS' EQUITY	1,549,803	1,439,558
	$4,357,073	$ 3,674,487

See notes accompanying the consolidated financial statements

QUESTAR CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Compre-hensive Income (Loss)
			(dollars in thousands)		
Balances at January 1, 2003	82,053,760	$298,718	$ 868,702	($ 28,659)	
Common stock issued	1,293,439	21,855			
Common stock repurchased	(113,248)	(3,462)			
2003 net income			173,616		$173,616
Dividends paid ($0.78 per share)			(64,538)		
Income tax benefit from stock-based compensation		4,462			
Amortization of nonvested stock		2,041			
Acquisition of minority interest		1,169			
Other comprehensive income					
Change in unrealized loss on energy hedges, net of income taxes of $9,429				(15,755)	(15,755)
Minimum pension liability, net of income taxes of $1,930				3,116	3,116
Balances at December 31, 2003	83,233,951	324,783	977,780	(41,298)	$160,977

Common stock issued	1,335,103	29,145			
Common stock repurchased	(127,714)	(4,778)			
2004 net income			229,301		$229,301
Dividends paid ($0.85 per share)			(71,363)		
Income tax benefit from stock-based compensation		6,479			
Amortization of nonvested stock		2,388			
Other comprehensive income					
Change in unrealized loss on energy hedges,					
net of income taxes of $5,677				(9,515)	(9,515)
Minimum pension liability, net of income					
taxes of $2,084				(3,364)	(3,364)
Balances at December 31, 2004	84,441,340	358,017	1,135,718	(54,177)	$216,422

QUESTAR CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Stock		Retained	Accumulated Other Comprehensive	Compre-hensive
	Shares	Amount	Earnings	Income (Loss)	Income (Loss)
			(dollars in thousands)		
Common stock issued	1,035,634	16,941			
Common stock repurchased	(157,137)	(9,736)			
2005 net income			325,681		$325,681
Dividends paid ($0.89 per share)			(75,616)		
Income tax benefit from stock-based compensation		13,882			
Amortization of nonvested stock		4,194			
Other comprehensive income					
Change in unrealized loss on energy hedges,					

net of income taxes of $95,467					(155,952)	(155,952)
Minimum pension liability, net of income taxes of $5,667					(9,149)	(9,149)
Balances at December 31, 2005	85,319,837		$383,298	$1,385,783	($219,278)	$160,580

See notes accompanying the consolidated financial statements

QUESTAR CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
OPERATING ACTIVITIES			
Net income	$ 325,681	$ 229,301	$ 173,616
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation, depletion and amortization	255,540	225,879	201,809
Deferred income taxes	92,154	106,978	80,811
Abandonment and impairment of gas, oil and other related properties	7,931	15,758	4,151
Amortization of nonvested stock	4,194	2,388	2,041
Net (gain) loss from asset sales	(4,742)	(336)	525
Impairment of California segment of Southern Trails Pipeline	16,000		
Income from unconsolidated affiliates, net of cash distributions	2,548	3,164	1,974
Other	201	286	(166)
Cumulative effect of accounting change			5,580
	699,507	583,418	470,341
Changes in operating assets and liabilities			
Accounts receivable	(131,702)	(37,496)	(67,628)
Inventories	(39,986)	(32,942)	(12,144)
Prepaid expenses and other	(6,653)	(7,312)	(1,348)

Accounts payable and accrued expenses	183,420	95,029	23,300
Rate-refund obligation	(25,343)	404	24,939
Federal income taxes	400	(1,432)	2,412
Purchased-gas adjustments	(3,999)	(35,301)	(13,834)
Other assets	11,006	(1,832)	1,489
Other liabilities	11,610	19,278	8,846
NET CASH PROVIDED FROM OPERATING ACTIVITIES	698,260	581,814	436,373
INVESTING ACTIVITIES			
Capital expenditures			
Property, plant and equipment	(715,886)	(441,483)	(309,928)
Other investments		(1,000)	(15,411)
Total capital expenditures	(715,886)	(442,483)	(325,339)
Proceeds from asset dispositions	19,228	7,189	10,975
NET CASH USED IN INVESTING ACTIVITIES	(696,658)	(435,294)	(314,364)

QUESTAR CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
FINANCING ACTIVITIES			
Common stock issued	16,941	29,145	21,855
Common stock repurchased	(9,736)	(4,778)	(3,462)
Long-term debt issued	250,000		110,000
Long-term debt repaid	(200,012)	(71,993)	(249,990)
Change in short-term debt	26,500	(37,500)	56,500
Other financing		(255)	(110)
Dividends paid	(75,616)	(71,363)	(64,538)
NET CASH USED IN FINANCING ACTIVITIES	8,077	(156,744)	(129,745)
Change in cash and cash equivalents	9,679	(10,224)	(7,736)
Beginning cash and cash equivalents	3,681	13,905	21,641
Ending cash and cash equivalents	$ 13,360	$ 3,681	$ 13,905

See notes accompanying the consolidated
financial statements

QUESTAR CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Summary of Significant Accounting Policies

Nature of Business

Questar is a natural gas focused energy company with four principal lines of business gas and oil exploration and production, midstream field services, interstate gas transportation and retail gas distribution. Market Resources operates through four principal subsidiaries. Questar E&P acquires, explores for, develops and produces natural gas, oil, and NGL; Wexpro manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas; Gas Management provides midstream field services including natural gas-gathering and processing services for affiliates and third parties; and Energy Trading markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned limited liability company, Clear Creek Storage Company, LLC, owns and operates an underground natural gas-storage reservoir. Questar Pipeline provides interstate natural gas transportation, storage, processing and treating services. Questar Gas provides retail natural gas distribution.

Principles of Consolidation

The consolidated financial statements contain the accounts of Questar and subsidiaries. The consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and with the instructions for annual reports on Form 10-K and Regulations S-X and S-K. All significant intercompany accounts and transactions have been eliminated in consolidation.

Investments in Unconsolidated Affiliates

Questar 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 formulate estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Revenue Recognition

Market Resources subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues reflect the impact of price-hedging instruments. Revenues associated with the production of gas and oil are accounted for using the sales method, whereby revenue is recognized as gas and oil is sold to purchasers. A liability is recorded to the extent that the company has sold volumes in excess of its share of remaining gas and oil reserves in an underlying property. Market Resources imbalance obligations at December 31, 2005 and 2004, were $2.5 million and $3.0 million, respectively. Energy Trading gas and oil marketing revenues are recognized on a gross basis.

The straight fixed-variable rate design used by Questar Pipeline, which allows for recovery of substantially all fixed costs in the demand or reservation charge, reduces the earnings impact of volume changes on gas-transportation and storage operations. Rate-regulated companies may collect revenues subject to possible refunds and establish reserves pending final orders from regulatory agencies.

Questar Gas records revenues for gas delivered to residential and commercial customers but not billed as of the end of the accounting period. Unbilled gas deliveries are estimated for the period from the date meters are read to the end of the month. Approximately one-half month of revenue is estimated in any period. Gas costs and other variable costs are recorded on the same basis to ensure proper matching of revenues and expenses. Questar Gas tariff allows for monthly adjustments to customer charges to approximate the effect of abnormal weather on nongas revenues. The weather-normalization adjustment significantly reduces the impact of weather on gas-distribution earnings.

Regulation

Questar Gas is regulated by the Public Service Commission of Utah (PSCU) and the Public Service Commission of Wyoming (PSCW). The Idaho Public Utilities Commission has contracted with the PSCU for rate oversight of Questar Gas's operations in a small area of southeastern Idaho. Questar Pipeline is regulated by the Federal Energy Regulatory Commission (FERC). Market Resources, through its subsidiary Clear Creek Storage Company, LLC, operates a gas-storage facility under the jurisdiction of the FERC. These regulatory agencies establish rates for the storage, transportation and sale of natural gas. The regulatory agencies also regulate, 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.

The financial statements of rate-regulated businesses are presented in accordance with regulatory requirements. Methods of allocating costs to time periods, in order to match revenues and expenses, may differ from those of other businesses because of cost-allocation methods used in establishing rates. Regulatory assets and liabilities are recorded to reflect these timing differences.

Purchased-Gas Adjustments

Questar Gas accounts for purchased-gas costs in accordance with procedures authorized by the PSCU and the PSCW. Purchased-gas costs that are different from those provided for in present rates are accumulated and recovered or credited through future rate changes. Questar Gas may hedge a portion of its natural gas supply to mitigate price fluctuations for gas-distribution customers. The benefits and the costs of hedging are included in the purchased-gas-adjustment account. The regulatory commissions allow Questar Gas to record periodic mark-to-market adjustments for commodity price-hedging contracts in the purchased-gas-adjustment account. Questar Gas was not a party to hedging transactions as of December 31, 2005 or 2004.

Other Regulatory Assets and Liabilities

In addition to purchased-gas adjustments, rate-regulated businesses are permitted to defer recognition of certain costs, which is different from the accounting treatment required of nonrate-regulated businesses. See Note 7 to the consolidated financial statements for a description and comparison of regulatory assets and liabilities as of December 31, 2005 and 2004.

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.

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, purchasing related support equipment and facilities are capitalized. 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 of production and general corporate activities are expensed in the period incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production depreciation, depletion and amortization rate would be significantly affected.

Capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Cost-of-service gas and oil operations

The successful efforts method of accounting is used for cost-of-service gas and oil properties owned by Questar Gas and managed and developed by Wexpro. Cost-of-service gas and oil properties are properties for which the operations and return on investment are subject to the Wexpro Agreement (see Note 14). 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:

	2005	2004	2003

Gas and oil properties, per Mcfe	$1.18	$1.04	$0.98
Cost-of-service gas and oil properties, per Mcfe	0.77	0.69	0.65

Depreciation, depletion and amortization for the remaining Company properties is based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using either a straight-line or unit-of-production method. Investment in gas-gathering and processing fixed assets is charged to expense using either the straight-line or unit-of-production method depending upon the facility.

Major categories of fixed assets in gas-distribution, transportation and storage operations are grouped together and depreciated on a straight-line method. Under the group method, salvage value is not considered when determining depreciation rates. Gains and losses on asset disposals are recorded as adjustments in accumulated depreciation. Gas-production fixed assets owned by Questar Gas are depreciated using the unit-of-production method.

The Company has not capitalized future-abandonment costs on a majority of its long-lived gas-distribution and transportation assets due to a lack of a legal obligation to restore the area surrounding abandoned assets. In these cases, the regulatory agencies have opted to leave retired facilities in the ground undisturbed rather than excavate and dispose of the assets. Average depreciation, depletion and amortization rates used in the 12 months ended December 31, were as follows:

	2005	2004	2003
Questar Pipeline transmission, processing and storage	3.3%	3.4%	3.2%
Questar Gas			
Distribution plant	3.9%	3.7%	3.7%
Gas wells, per Mcf	$0.11	$0.11	$0.13

Impairment of Long-Lived Assets

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset s carrying value. Triggering events could include an impairment of gas and oil reserves caused by mechanical problems, a faster-than-expected decline of reserves, lease-ownership issues, an other-than-temporary decline in gas and oil prices and changes in the utilization of pipeline assets. If impairment is indicated, fair value is calculated using a discounted-cash-flow approach. Cash-flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices and operating costs.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the amount paid over the fair value of net assets acquired in a business combination and is not subject to amortization. Rights of way and FCC licenses are examples of intangible assets. Intangible assets are either amortized or not amortized. Investments in pipeline rights of way are amortized. FCC licenses have indefinite lives and are not amortized. Goodwill and indefinite lived intangible assets are tested for impairment at a minimum of once a year or when a triggering event occurs. If a triggering event occurs, the undiscounted net cash flows of the intangible asset or entity to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted-cash-flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors.

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

The Company capitalizes interest costs when applicable. The FERC requires the capitalization of AFUDC during the construction period of rate-regulated plant and equipment. The Wexpro Agreement requires capitalization of AFUDC on cost-of-service construction projects. AFUDC amounted to $0.7 million in 2005, $0.3 million in 2004 and $1.1 million in 2003 and is included in Interest and Other Income in the Consolidated Statements of Income. Interest Expense was reduced by $1.0 million, $0.2 million and $0.1 million in 2005, 2004 and 2003, respectively.

Hedging Instruments

The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value or cash flows. If the hedged exposure is a fair-value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting gain or loss from the change in fair value of the hedged item. If the hedged exposure is a cash-flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in the current period income statement. A derivative instrument qualifies as a cash-flow hedge if all of the following tests are met:

-

The item to be hedged exposes the Company to price risk.

-

The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.

-

At the inception of the hedge and throughout the hedge period, there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying hedged item.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are included in income in the same period that the underlying production or other contractual commitment is delivered. When a derivative instrument is associated with an anticipated transaction that is no longer probable, the gain or loss on the derivative is reclassified from other comprehensive income and recognized currently in the results of operations. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

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 associated with accounts receivable amounted to $8.8 million, $5.5 million and $3.7 million for the years ended December 31, 2005, 2004 and 2003, respectively. The allowance for bad-debt expenses was $7.7 million and $6.1 million at December 31, 2005, and 2004, respectively. Questar Gas s retail-gas operations account for a majority of the bad-debt expense. Questar Gas estimates bad-debt expense as 1.0% of general-service revenues with periodic adjustments. Uncollected accounts are generally written off five months after gas is delivered and interest is no longer accrued.

Income Taxes

Questar and its subsidiaries file a consolidated federal income tax return. Deferred income taxes have been provided for the temporary timing differences arising between the book and tax-carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. Questar Gas and Questar Pipeline use the deferral method to account for investment-tax credits as required by regulatory commissions.

Earnings Per Share (EPS)

Basic earnings per share are computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during the accounting period. Diluted EPS include the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options plus an estimated number of nonvested restricted shares.

Stock-Based Compensation

Questar issues stock options and nonvested restricted shares to employees and non-employee directors. The Company historically accounted for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion 25, Accounting for Stock Issued to Employees and related interpretations. No compensation expense was recorded because the exercise price of options equals the market price on the date of grant. The Company adopted the pro forma income disclosure features described in SFAS 123 Accounting for Stock-Based Compensation as amended by SFAS 148 Accounting for Stock-Based Compensation-Transition and Disclosure. The following table shows pro forma income had stock options been expensed based on fair value calculated using the Black-Scholes-Merton model:

	Year Ended December 31,		
	2005	2004	2003

	(in thousands)		
Net income, as reported	$325,681	$229,301	$173,616
Deduct: Stock-based compensation expense determined under fair-value-based methods, (after tax)	(1,712)	(3,084)	(6,051)
Pro forma net income	$323,969	$226,217	$167,565
Earnings per share			
Basic, as reported	$3.84	$2.74	$2.10
Basic, pro forma	3.82	2.70	2.03
Diluted, as reported	3.74	2.67	2.06
Diluted, pro forma	3.72	2.64	1.99

Net income, as reported in the table above, reflects compensation costs related to restricted stock awards. Restricted shares are valued at the market price on the grant date and amortized to expense over the vesting period. Expense amounted to $4.2 million, $2.4 million and $2.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

In December 2004 the Financial Accounting Standards Board (FASB) issued Statement 123 (revised 2004), (SFAS 123R), Share Based Payment, which replaces SFAS 123 and supersedes APB Opinion 25. SFAS 123R eliminates the alternative to use APB Opinion 25 s intrinsic value method of accounting that was provided in SFAS 123 as originally issued. Pro forma disclosure will no longer be allowed. The Company s effective date for implementation of SFAS 123R is January 1, 2006. Alternative phase-in methods are allowed under SFAS 123R. The Company intends to use the modified prospective phase-in method that requires recognition of compensation costs for all share based payments granted, modified or settled after the date of implementation as well as for any awards that were granted prior to the implementation date for which the required service has not yet been performed. The Company believes that the modified prospective phase-in method will not have a material effect on the Company s operating results or financial position.

Comprehensive Income

Comprehensive income is the sum of net income as reported in the Consolidated Statement of Income and other comprehensive income or loss reported in the Consolidated Statement of Common Shareholders' Equity. Other comprehensive income or loss includes changes in the market value of gas and oil price derivatives and recognition of additional pension liability. 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 physical gas, oil or NGL underlying the derivative instrument is sold or pension costs are accrued. The balances of accumulated other comprehensive loss, net of income taxes, at December 31, were as follows:

	2005	2004
	(in thousands)	
Unrealized loss on energy-hedging transactions	($198,102)	($42,150)
Additional pension liability	(21,176)	(12,027)
Accumulated other comprehensive loss	($219,278)	($54,177)

Business Segments

Line of business information is presented according to senior management s basis for evaluating performance considering differences in the nature of products, services and regulation. Certain intersegment sales include intercompany profit.

Recent Accounting Developments

In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143 (SFAS 143). FIN 47 clarifies the term conditional asset retirement obligation as used in SFAS 143 and requires a liability to be recorded if the fair value of the obligation can be reasonably estimated. The types of asset retirement obligations that are covered by FIN 47 are those for which an entity has a legal obligation to perform an asset retirement activity; however, the timing and/or method of settling the obligation are conditional on a future event that may or may not be within the control of the entity. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 in 2005 did not have a significant impact on Questar s results of operation or financial position.

In June 2005, the FASB issued SFAS 154, Accounting Changes and Error Corrections, a replacement of existing accounting pronouncements. SFAS 154 modifies accounting and reporting requirements when a company voluntarily chooses to change an accounting principle or correct an accounting error. SFAS 154 requires retroactive restatement of prior period financial statements unless it is impractical. Previous accounting guidelines allowed recognition by cumulative effect in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In July 2005, the FASB issued an exposure draft of a Proposed Interpretation Accounting for Uncertain Tax Positions, an Interpretation of FASB Statement 109. The exposure draft seeks to reduce perceived diversity in practice associated with recognition and measurement in the accounting for income taxes. The exposure draft would apply to all tax positions accounted for in accordance with SFAS 109, Accounting for Income Taxes. The exposure draft requires that a tax position meet a probable recognition threshold for the benefit of the uncertain tax position to be recognized in the financial statements. This threshold is to be met assuming that the tax authorities will examine the uncertain tax position. The exposure draft contains guidance with respect to the measurement of the benefit that is recognized for an uncertain tax position, when that benefit should be derecognized, and other matters. The proposed effective date has been postponed. The Company has not evaluated the potential effect of this proposed change in accounting principle.

The FASB initiated a project in November 2005 to reconsider the accounting for pensions and other postretirement benefits. Proposed changes identified in the first phase of the project will likely result in balance sheet changes. A preliminary decision, if approved, would cause companies to record the over or underfunded status of defined benefit plans on the balance sheet. The over or under funded position would be measured by the difference in the fair value of plan assets and the projected benefit obligation. The projected benefit obligation includes future salary changes. The second phase will address asset and liability measurement issues and will affect the income statement. Elimination of unrecognized actuarial gains or losses is among the considered changes. The FASB expects to issue an exposure draft in the first quarter of 2006. First phase changes may be in effect for the 2006 reporting year. The Company has not measured the impact of these proposed changes.

Reclassifications

Certain reclassifications were made to prior-year consolidated financial statements to conform with the 2005 presentation of lines of business disclosures, gathering and processing revenues and expenses, current portions of deferred income taxes and production taxes, and regulatory asset and liabilities.

Note 2 Rate Regulation

Gas-Processing Dispute

On August 1, 2003, the Utah Supreme Court issued an order reversing an August 2000 decision made by the PSCU concerning certain natural gas-processing costs incurred by Questar Gas to manage the heat content of its gas supply. As a result of the court s order, Questar Gas recorded a $29 million liability for a potential refund to gas-distribution customers. This liability included revenue received for processing costs and interest from June 1999 through September 2004. On August 30, 2004, the PSCU ruled that Questar Gas failed in 1999 to prove that its decision to contract for gas processing with an affiliate was prudent. Questar Gas reduced its rates on September 1, 2004, to eliminate the collection of gas-processing costs and on October 1, 2004, began refunding previously collected costs, plus interest, over a 12-month period.

In response to a Questar Gas petition, the PSCU clarified that its order did not preclude recovery of ongoing and certain past-processing costs. Questar Gas has requested ongoing rate coverage for gas-processing costs in its pass-through filings, but is not currently collecting these costs in rates. On January 31, 2005, Questar Gas filed a rate request with the PSCU to recover $5.7 million per year of gas-processing costs through its gas-balance account. The $5.7 million is Utah s share of the estimated $6 million annual cost of operating the gas-processing plant. The Wyoming share has been recovered in rates.

In October 2005, Questar Gas, the Utah Division of Public Utilities and the Committee of Consumer Services submitted a stipulation to the PSCU to resolve issues related to cost recovery of carbon dioxide processing activities. The PSCU held a hearing on October 20, 2005, and issued an order on January 6, 2006 approving the stipulation beginning on February 1, 2005. The stipulation provides for the recovery of 90% of the non fuel cost of service for processing and 100% of the fuel costs up to 360 Mdth per year. Half of the third-party processing revenues are shared with customers after the first $0.4 million. In the fourth quarter of 2005 Questar Gas reduced expenses for recovery of gas costs by $4.9 million for the period from February 1, 2005 to December 31, 2005.

Fuel-Gas Reimbursement Percentage (FGRP)

During the fourth quarter of 2004, the FERC issued an order to Questar Pipeline in a case involving the annual FGRP. The FERC previously granted Questar Pipeline s request to increase the FGRP effective January 1, 2004. In its order the FERC approved the FGRP but also ruled that Questar Pipeline was required to credit to transportation customers proceeds from the sale of natural gas liquids recovered from its hydrocarbon dewpoint facilities at the Kastler plant in northeastern Utah. Questar Pipeline accrued a potential liability equal to any liquid revenues from the dewpoint plant. Through June 30, 2005, Questar Pipeline had reduced revenues by $5.4 million as a credit to customers, including $0.7 million recorded in the first half of 2005.

Questar Pipeline made an annual FGRP filing with the FERC on November 30, 2004, requesting an increase in the FGRP to 2.6%. On December 30, 2004, the FERC approved the request on an interim basis subject to refund and final resolution of the 2004 FGRP proceeding. Several shippers filed comments with the FERC protesting the FGRP level.

On June 17, 2005, Questar Pipeline filed an uncontested offer of settlement with the FERC to resolve the outstanding issues in the 2004 and 2005 FGRP filings. This settlement with customers was approved July 26, 2005, and contains the following terms: (a) the settlement will cover the period from June 1, 2005 through December 31, 2007; (b) no adjustments will be made to FGRP amounts collected by Questar Pipeline prior to June 2005; (c) one-half of the Kastler plant liquid revenues from August 2001 through December 2007 will be refunded to customers and the remaining revenues will be retained by Questar Pipeline; and (d) Questar Pipeline will reduce the FGRP amount collected from customers from 2.6% to 2.1% effective June 1, 2005. This percentage consists of 1.95% of ongoing FGRP related costs and 0.15% of prior-period amortization of costs. If actual ongoing costs is less than the 1.95%, the difference will be shared equally with customers beginning January 2006. Questar Pipeline recorded the impact of the settlement in third quarter 2005 increasing liquid revenues by $2.7 million and net income by $1.7 million.

The actual FGRP for the 12-month period ended September 30, 2005, was 1.73%. Pursuant to the settlement, Questar Pipeline reduced its FGRP for calendar year 2006 to 1.84% plus the 0.15% of prior period costs.

State Rate Regulation

Questar Gas files periodic applications with the PSCU and PSCW requesting permission to reflect annualized gas-cost increases or decreases in its rates. Gas costs are passed on to customers on a dollar-for-dollar basis with no markup.

FERC Order 2004

FERC Order No. 2004, which defines standards of conduct for transmission providers, became effective on September 22, 2004. These standards of conduct are designed to ensure that employees engaged in transmission system operations function independently from employees of marketing and energy affiliates. In addition, a transmission provider must treat all transmission customers on a non-discriminatory basis and must not operate its transmission system to preferentially benefit its marketing or energy affiliates. Questar Pipeline has determined that all Market Resources subsidiaries except Gas Management are marketing or energy affiliates. Questar Gas is not an energy affiliate. Questar Pipeline and other Questar companies have adopted new procedures to comply with this order.

Note 3 Asset Retirement Obligations (ARO)

Questar recognizes ARO in accordance with SFAS 143 Accounting for Asset Retirement Obligations. SFAS 143 addresses the financial accounting and reporting of the fair value of legal obligations associated with the retirement of tangible long-lived assets. The Company s ARO applies primarily to plugging and abandonment costs associated with gas and oil wells and certain other properties. The fair value of abandonment costs are estimated and depreciated over the life of the related assets. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Questar adopted SFAS 143 on January 1, 2003. Changes in asset retirement obligations were as follows:

	2005	2004
	(in thousands)	
Balance at January 1,	$67,288	$61,358
Accretion	4,261	2,868
Additions	7,883	3,159
Revisions		695
Retirements and properties sold	(1,309)	(792)
Balance at December 31,	$78,123	$67,288

Wexpro activities are governed by a longstanding agreement with the states of Utah and Wyoming (the Wexpro Agreement). The accounting treatment of reclamation activities associated with ARO for properties administered under the Wexpro Agreement is spelled out in a guideline letter between Wexpro and the Utah Division of Public Utilities and the staff of the 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, 2005, $3.7 million was held in this trust invested in a short-term bond index fund.

Note 4 Property, Plant and Equipment

The details of property, plant and equipment and accumulated depreciation, depletion and amortization follow.

	December 31,	
	2005	2004
	(in thousands)	
Property, plant and equipment		
Market Resources		
Gas and oil properties		
Proved properties	$2,047,868	$1,602,143
Unproved properties, not being depleted	41,567	62,678
Support equipment and facilities	18,389	16,932
	2,107,824	1,681,753
Cost-of-service gas and oil properties	561,501	561,162
Gathering and processing	323,933	223,134
Marketing and other	36,244	35,283
Market Resources total	3,029,502	2,456,332
Questar Pipeline	1,101,512	1,055,030
Questar Gas	1,383,362	1,315,537
Corporate and other operations	13,621	50,872
	$5,527,997	$4,877,771
Accumulated depreciation, depletion and amortization		
Market Resources		
Gas and oil properties	$ 731,098	$ 600,366
Cost-of-service gas and oil properties	277,648	262,523
Gathering and processing	82,237	70,728

Marketing and other	4,560	3,650
Market Resources total	1,095,543	937,267
Questar Pipeline	381,387	355,475
Questar Gas	615,934	572,290
Corporate and other operations	7,591	28,147
	2,100,455	1,893,179
Net Property, Plant and Equipment	$3,427,542	$2,984,592

Questar E&P proved and unproved leaseholds had a net book value of $344.0 million and $361.9 million at December 31, 2005, and 2004, respectively. The Company currently has no completed exploratory wells classified as unproved properties, not being depleted.

Impairment of the California segment of the Southern Trails Pipeline

The California segment of the Southern Trails Pipeline, which extends from near the California-Arizona border to Long Beach, California, is currently not in service. Questar Pipeline is pursuing several options to sell or place this line in service.

Questar Pipeline performed an impairment test on the California segment of Southern Trails during the fourth quarter of 2005 and recognized an impairment of $16 million, reducing its net investment to approximately $35 million. The value realized by Questar Pipeline for the California segment of Southern Trails, either by putting the line in service or selling the line, may vary from this amount.

Note 5 Investment in Unconsolidated Affiliates

Questar uses the equity method to account for investments in unconsolidated affiliates where the Company does not have control. These entities are engaged in gathering and compressing natural gas and have no debt obligations with third-party lenders. The principal affiliates and Questar s ownership percentage as of December 31, 2005, were Rendezvous Gas Services, LLC, a limited liability corporation, (50%) and Canyon Creek Compression Company, a general partnership (15%). Operating results representing 100% of these businesses are listed below:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		

Revenues	$21,605	$16,857	$15,916
Operating income	14,529	10,280	9,775
Income before income taxes	14,679	10,312	9,807
Current assets, at end of period	6,405	6,626	5,167
Noncurrent assets, at end of period	63,233	66,010	74,111
Current liabilities, at end of period	2,959	1,338	909
Noncurrent liabilities, at end of period	1,843	1,073	1,589

Note 6 Goodwill and Other Intangible Assets

The goodwill balance by line of business is listed below:

	December 31, 2005 and 2004 (in thousands)
Questar E&P	$61,423
Questar Pipeline	4,185
Questar Gas	5,652
	$71,260

As of December 31, 2005 and 2004, the Company held about $3.3 million of intangible assets with indefinite lives. Intangible assets at December 31, 2005, primarily rights of way for pipelines, subject to amortization, amounted to $10.8 million, net of accumulated amortization of $3.0 million. At December 31, 2004, intangible assets amounted to $11.2 million net of accumulated amortization of $2.7 million. The weighted-average amortization period was 32 years.

Note 7 Other Regulatory Assets and Liabilities

The Company has other regulatory assets and liabilities in addition to purchased-gas adjustments described in Note 1 of the consolidated financial statements included in Item 8 in Part II of this Annual Report. The regulated entities recover these costs but do not generally receive a return on these assets. Questar Gas has a regulatory asset representing a retroactive charge for the abandonment costs associated with gas wells operated on its behalf by Wexpro. The regulatory asset will be reduced over the next 15 years following an amortization schedule or as cash is paid to plug and abandon wells.

Gains and losses on the reacquisition of debt by rate-regulated companies are deferred and amortized as debt expense over either the would-be remaining life of the retired debt. The reacquired debt costs had a weighted-average life of approximately 12 years as of December 31, 2005. The cost of the early retirement windows offered to employees of rate-regulated subsidiaries was deferred and amortized over a five-year period, which concluded in 2005. The rate-regulated businesses are allowed to recover certain deferred taxes from customers. Production taxes on cost-of-service gas production are recorded when the gas is produced and recovered from customers when taxes are paid, generally within 12 months.

Questar Pipeline has accrued a regulatory liability for the collection of postretirement medical costs allowed in rates which exceeded actual charges. Regulatory liabilities are included with Other Long-Term Liabilities in the Consolidated Balance Sheets. A list of regulatory assets and liabilities follows:

	December 31,	
	2005	2004
	(in thousands)	
Regulatory assets		
Cost of reacquired debt	$15,997	$17,329
Asset retirement obligations cost -of-service gas wells	4,576	5,097
Deferred production taxes	4,861	4,258
Early retirement costs		2,418
Income taxes recoverable from customers	3,249	3,598
Questar Gas pipeline-integrity costs	3,111	1,042
Other	973	700
	$32,767	$34,442

	December 31,	
	2005	2004
	(in thousands)	
Regulatory liabilities		
Postretirement medical	$4,227	$3,596
Income taxes recoverable from customers	2,391	2,890
	$6,618	$6,486

Note 8 Debt

The Company has short-term line-of-credit commitments from several banks under which it may borrow up to $420 million at December 31, 2005. These credit lines have interest rates generally below the prime interest rate. Commercial-paper borrowings with initial maturities of less than one year are backed by the short-term line-of-credit arrangements. The details of short-term debt are as follows:

	December 31, 2005	December 31, 2004
	(in thousands)	
Commercial paper with variable-interest rates	$94,500	$68,000
Weighted-average interest rate	4.43%	2.45%

The details of long-term debt are listed in the table below. All notes and the term loan are unsecured obligations and rank equally with all other unsecured liabilities. Market Resources revolving credit agreement had no borrowings outstanding at December 31, 2005 or 2004, but was fully drawn during part of 2005. The credit agreement carries an annual commitment fee of 0.125% of the unused balance. At December 31, 2005, Market Resources and Questar Gas could pay dividends of $1.08 billion and $342 million, respectively, without violating the terms of their debt covenants:

	December 31, 2005	December 31, 2004
	(in thousands)	
Market Resources		
7.0% notes due 2007	$200,000	$200,000
7.5% notes due 2011	150,000	150,000
$200 million revolving credit agreement due 2010	-	-
Questar Pipeline		
Medium-term notes 5.85% to 7.55%, due 2008 to 2018	310,400	310,400
Questar Gas		
Medium-term notes 5.00% to 7.58%, due 2007 to 2018	273,000	273,000
Five-year term loan 4.92% at December 31, 2005, due 2010	50,000	
Corporate and other operations	99	112
Total long-term debt outstanding	983,499	933,512
Less current portion	(14)	(12)
Less unamortized-debt discount	(285)	(305)
	$983,200	$933,195

Maturities of long-term debt for the five years following December 31, 2005, are as follows:

	(in thousands)
2006	$ 14
2007	210,016
2008	101,318
2009	42,020
2010	50,023

Cash paid for interest was $67.8 million in 2005, $66.8 million in 2004 and $70.2 million in 2003.

On December 15, 2005, Questar Gas borrowed $50 million from a bank under a five-year term loan agreement. The loan s interest rate varies periodically with changes in short-term interest rates available in the credit markets.

Note 9 Earnings Per Share and Common Stock

Earnings per share (EPS)

Basic EPS is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during the accounting period. Diluted EPS include the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options plus an estimated number of nonvested restricted shares. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Weighted-average basic common shares			

outstanding		84,791	83,759	82,697
Potential number of shares issuable under				
stock option plans	2,343		1,963	1,493
Average diluted common shares outstanding	87,134		85,722	84,190

In the past three years, Questar issued shares under the terms of the Dividend Reinvestment and Stock Purchase Plan, Employee Investment Plan and Long-Term Stock Incentive Plan.

<u>Dividend Reinvestment and Stock Purchase Plan (Reinvestment Plan)</u>

The Reinvestment Plan allows parties interested in owning Questar common stock to reinvest dividends or invest additional funds in common stock. The Company can issue new shares or buy shares in the open market to meet shareholders' purchase requests. The Reinvestment Plan issued total shares of 2,675, 185,809 and 208,400 in 2005, 2004 and 2003, respectively. At December 31, 2005, 1,093,361 shares were reserved for future issuance.

<u>Employee Investment Plan (EIP)</u>

The EIP allows eligible employees to purchase shares of Questar common stock or other investments through payroll deduction. The Company matches 80% of employees' pre-tax purchases up to a maximum of 6% of their qualifying earnings. In addition, each year the Company makes a nonmatching contribution of $200 to each eligible employee. The Company's expense equals its contribution. Questar's expense for the EIP amounted to $6.2 million, $5.8 million and $5.5 million for the years ended December 31, 2005, 2004 and 2003, respectively. The number of shares in the EIP increased by 16,928, 143,436 and 176,626 in 2005, 2004 and 2003, respectively. In 2005, the Company s contributions to the EIP were primarily used to purchase shares on the open market.

<u>Long-Term Stock Incentive Plan (LTSIP)</u>

The Company has an omnibus LTSIP for officers, directors, and employees under which it can issue common stock options and nonvested restricted stock. The current plan was amended March 1, 2001, and approved by shareholders to combine optionees under one plan and reserve an additional 8,000,000 shares. The Company's separate Stock Option Plan for Directors terminated, but still has outstanding options granted. Stock options for participants have terms ranging from five to ten years with a majority issued with a ten-year term. Options held by employees generally vest in four equal, annual installments beginning six months after grant. Options granted to nonemployee directors generally vested in one installment six months after grant. Options vest on an accelerated basis in the event of retirement and have postretirement exercise periods. The option price equals the closing market price of the stock on the grant date; therefore no compensation expense was recorded. There were 5,507,161 shares available for future grant at December 31, 2005. Transactions involving options in the LTSIP are summarized as follows:

	Outstanding Options	Price Range	Weighted-Average Price
Balance at January 1, 2003	4,975,739	$13.69 - $28.01	$21.29
Granted	1,156,500	27.11 - 29.71	27.18
Cancelled	(13,250)	22.95 - 28.01	26.29
Exercised	(1,138,770)	13.69 - 28.01	19.03
Balance at December 31, 2003	4,980,219	13.69 - 29.71	23.16
Granted	25,000	35.10	35.10
Cancelled	(11,000)	15.00 - 27.11	25.06
Exercised	(979,148)	13.69 - 35.10	20.62
Balance at December 31, 2004	4,015,071	13.69 - 35.10	23.85
Granted	250,000	48.66 - 77.14	71.44
Exercised	(1,013,083)	13.69 - 35.10	22.84
Balance at December 31, 2005	3,251,988	$13.69 - $77.14	$27.82

	Options Outstanding			Options Exercisable	
Range of Exercise prices	Number outstanding December 31, 2005	Weighted-average remaining contract life in years	Weighted-average exercise price	Number exercisable December 31, 2005	Weighted-average exercise price
$15.00 - $17.00	497,811	3.9	$15.50	497,811	$15.50
19.13 - 23.95	846,433	5.4	22.65	846,433	22.65
27.11 - 29.71	1,642,395	6.2	27.52	1,429,020	27.57
35.10 - 77.14	265,349	7.3	69.34	15,349	46.14
	3,251,988		27.82	2,788,613	24.02

A fair value of the stock options issued was determined on the grant date using the Black-Scholes-Merton option-valuation model. The fair-value calculation relies upon subjective assumptions and the use of a mathematical model to estimate value and may not be representative of future results. The Black-Scholes-Merton model was intended for measuring the value of options traded on an exchange. The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	2005	2004	2003
Fair value of options at grant date	$14.90, $21.46	$9.66	$7.54
Risk-free interest rate	3.97%, 4.17%	3.52%	3.80%
Expected price volatility	29.9%, 27.0%	28.4%	30.0%
Expected dividend yield	1.77%, 1.17%	2.34%	2.70%
Expected life in years	6.4, 5.0	7.3	7.3

Nonvested Restricted Stock

Nonvested restricted stock is granted under the terms of the LTSIP. These shares carry voting and dividend rights; however, sale or transfer is restricted. Restricted shares are valued at the closing price of Questar stock on the grant date and vest over a period of time generally three to five years. Compensation expense is recorded over the vesting period. Vested shares are distributed. Details of nonvested restricted shares were as follows:

	Shares	Price Range	Weighted Average Price
Balance at January 1, 2003	35,000	$23.95 - $27.26	$25.27
Granted	136,800	27.11 - 34.00	28.16
Forfeited	(5,750)	28.72	28.72
Distributed	(18,000)	23.95 - 27.88	26.11
Balance at December 31, 2003	148,050	23.95 - 34.00	27.71
Granted	132,400	34.90 - 50.60	35.99
Forfeited	(8,400)	28.72 - 36.90	31.73
Distributed	(33,610)	23.95 - 34.00	27.67
Balance at December 31, 2004	238,440	27.11 - 50.60	32.17
Granted	113,975	48.66 - 86.03	53.98
Forfeited	(8,020)	28.72 - 51.00	36.48
Distributed	(44,354)	23.95 - 51.00	31.90
Balance at December 31, 2005	300,041	$27.11- $86.03	$40.38

Shareholder Rights

On February 13, 1996, Questar's Board of Directors declared a stock-right dividend for each outstanding share of common stock. The stock rights were issued March 25, 1996. The rights become exercisable if a person, as defined, acquires 15% or more of the Company's common stock or announces an offer for 15% or more of the common stock. Each right initially represents the right to buy one share of the Company's common stock for $87.50. Once any person acquires 15% or more of the Company's common stock, the rights are automatically modified. Each right not owned by the 15% owner becomes exercisable for the number of shares of Questar's stock that have a market value equal to two times the exercise price of the right. This same result occurs if a 15% owner acquires the Company through a reverse merger when Questar and its stock survive. If the Company is involved in a merger or other business combination at any time after the rights become exercisable, rightholders will be entitled to buy shares of common stock in the acquiring Company having a market value equal to twice the exercise price of each right. The rights may be redeemed by the Company at a price of $.005 per right until 10 days after a person acquires 15% ownership of the common stock. The rights expire March 25, 2006.

Note 10 Financial Instruments and Risk Management

The carrying value and estimated fair values of Questar's financial instruments were as follows:

	December 31, 2005		December 31, 2004	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	(in thousands)			
Financial assets				
Cash and cash equivalents	$ 13,360	$ 13,360	$ 3,681	$ 3,681
Energy-price-hedging contracts	1,972	1,972	11,149	11,149
Financial liabilities				
Short-term loans	94,500	94,500	68,000	68,000
Long-term debt	983,499	1,041,526	933,512	1,029,970
Energy-price-hedging contracts	321,093	321,093	78,650	78,650

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. Gas hedges are structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness.

Market Resources held gas-price-hedging contracts covering the price exposure for about 184.4 MMBtu of natural gas, 2.9 MMbbl of oil and 10.1 MMgal of NGL as of December 31, 2005. Gas Management, a subsidiary of Market Resources, uses forward-sales contracts to secure the price received for NGL processed from its plants. About 69% of the fair value of all contracts will settle and be reclassified from other comprehensive income in the next 12 months. A year earlier Market Resources hedging contracts covered the price exposure for about 135.6 million MMBtu of natural gas, 1.1 MMbbl of oil and 3.8 MMgal of NGL.

At December 31, 2005, the Company reported a liability, net of hedging assets, of $319.1 million from hedging activities. The offset to the hedging liability, net of income taxes, was a $198.1 million unrealized loss on hedging activities recorded in other comprehensive loss in the shareholders' equity section of the consolidated balance sheet. 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 11 Income Taxes

Details of Questar's 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,		
	2005	2004	2003
	(in thousands)		
Federal			
Current	$ 97,792	$ 19,573	$ 20,166
Deferred	71,086	97,582	76,356
State			
Current	12,213	1,544	383
Deferred	7,227	11,276	6,057
Deferred investment-tax credits	(395)	(395)	(399)
	$187,923	$129,580	$102,563

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,		
	2005	2004	2003
	(in percentages)		
Federal income taxes statutory rate	35.0	35.0	35.0
Increase (decrease) as a result of:			
State income taxes, net of federal income tax benefit	2.5	2.4	1.5
Domestic production benefit	(0.3)		
Percentage depletion	(0.1)	(0.3)	
Amortize investment-tax credits related to rate-regulated assets	(0.1)	(0.1)	(0.1)
Amortize unrecorded timing difference related to rate-regulated assets		0.2	0.3
Tax benefits from dividends paid to ESOP	(0.3)	(0.4)	(0.5)
Other	(0.1)	(0.7)	0.2
Effective income tax rate	36.6	36.1	36.4

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

	December 31,	
	2005	2004
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	$675,469	$602,163
Deferred tax assets:		
Energy price hedging	37,516	4,742
Alternative minimum tax carried forward		17,409
Employee benefits and compensation costs	13,766	7,566
Total deferred tax assets	51,282	29,717
Deferred income taxes noncurrent	$624,187	$572,446
Deferred income taxes current:		
Energy price hedging	($83,286)	($20,593)
Purchased-gas adjustment	15,144	13,624
Other	(18,592)	(19,044)
Deferred income taxes current	($86,734)	($26,013)

Cash paid for income taxes was $86.5 million, $23.3 million, and $18.9 million in 2005, 2004 and 2003, respectively.

Note 12 Commitments and Contingencies

Questar is involved in a variety of pending legal disputes involving commercial litigation arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact on Questar cannot be predicted with certainty, management believes that the outcome of these cases will not have a material adverse effect on financial position, operating results or liquidity. A discussion of legal proceedings can be found in Item 3 of Part I in this Annual Report.

Commitments

Historically, 40 to 50% of Questar Gas gas-supply portfolio has been provided from company-owned gas reserves at the cost of service. The remainder of the gas supply has been purchased from more than 15 suppliers under approximately 38 gas-supply contracts using index-based or fixed pricing. Questar Gas has commitments to purchase gas of $264.7 million in 2006, $77.4 million in 2007, $38.7 million in 2008, and $27.0 million in 2009. Generally, at the conclusion of the heating season and after a bid process, new agreements for the next heating season are put in place. Questar Gas bought natural gas under purchase agreements amounting to $447 million, $336 million and $180 million in 2005, 2004 and 2003, respectively. In addition, Questar Gas makes use of various storage arrangements to meet peak-gas demand during certain times of the heating season.

Questar Gas has third-party transportation commitments requiring yearly payments of $4.3 million through 2018.

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

	(in millions)
2006	$5.5
2007	5.7
2008	5.4
2009	5.4
2010	5.2
2011 through 2018	$21.5

Questar sold its headquarters building under a sale-and-leaseback arrangement committing the Company to occupy the building through January 12, 2012. Questar has four renewal options of five years each, following expiration of the original lease in 2012. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows:

	(in millions)
2006	$5.2
2007	5.4
2008	5.4
2009	5.0
2010	4.9
after 2010	$7.6

Total minimum future-rental payments have not been reduced for sublease rentals of $339,000 in 2006, $237,000 in 2007, and $99,000 in 2008. Total rental expense amounted to $5.1 million in 2005, $5.2 million in both 2004 and 2003. Sublease-rental receipts were $292,000 in 2005, $176,000 in 2004 and $287,000 in 2003.

Note 13 Employee Benefits

Pension Plan

The Company has defined-benefit pension and postretirement medical and life insurance plans covering the majority of its employees. The Company s Employee Benefits Committee (EBC) has oversight over investment of retirement-plan and postretirement-benefit assets. The EBC uses a third-party consultant to assist in setting targeted-policy ranges for the allocation of assets among various investment categories. The majority of retirement-benefit assets were invested as follows:

	Actual Allocation		
	December 31, 2005	December 31, 2004	Policy Range
Domestic equity securities	45%	52%	40-50%
Foreign equity securities	21%	10%	15-25%
Debt securities	28%	32%	26-34%
Real estate securities	5%	6%	3-7%
Other	1%	-	0-3%

Questar sets aside funds for retirement-benefit obligations to pay benefits currently due and to build asset balances over a reasonable time period to pay future obligations. Questar is subject to and complies with minimum-required and maximum-allowed annual contribution levels mandated by the Employee Retirement Income Security Act (ERISA) and by the Internal Revenue Code. Subject to the above limitations, the Company seeks to fund the qualified retirement plan approximately equal to the yearly expense. The majority of assets set aside for postretirement-benefit obligations is assets commingled with those of the Company s ERISA-qualified retirement plan as permitted by section 401(h) of the Internal Revenue Code. The retirement plan (including commingled 401(h) assets within the plan) seeks investment returns consistent with reasonable and prudent levels of liquidity and risk.

The EBC allocates pension-plan and postretirement-medical-plan assets among broad asset categories and reviews the asset allocation at least annually. Asset-allocation decisions consider risk and return, future-benefit requirements, participant growth and other expected cash flows. These characteristics affect the level, risk and expected growth of postretirement-benefit assets.

The EBC uses asset-mix guidelines that include targets and permissible ranges for each asset category, return objectives for each asset group and the desired level of diversification and liquidity. These guidelines change from time to time based on an ongoing evaluation of each plan s risk tolerance.

Responsibility for individual security selection rests with each investment manager, who is subject to guidelines specified by the EBC. These guidelines are designed to ensure consistency with overall plan objectives.

The EBC sets performance objectives for each investment manager that are expected to be met over a three-year period or a complete market cycle, whichever is shorter. Performance and risk levels are regularly monitored to confirm policy compliance and that results are within expectations.

Pension-plan guidelines prohibit transactions between a fiduciary and parties in interest unless specifically provided for in ERISA. No restricted securities, such as letter stock or private placements, may be purchased for any investment fund. Questar securities may be considered for purchase at an investment manager s discretion, but within limitations prescribed by ERISA and other laws. There is no direct investment in Questar shares for the periods disclosed. Use of derivative securities by any investment managers is prohibited except where the committee has given specific approval or where commingled funds are utilized that have previously adopted permitting guidelines.

Pension-plan benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly pay period during the 10 years preceding retirement. Continued lower interest rates resulted in the Company recording an additional pension liability of $45.1 million and a $10.8 million intangible-pension asset in 2005. A summary of qualified-pension expense is as follows:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Service cost	$ 8,737	$ 8,077	$ 7,608
Interest cost	20,680	19,429	18,289
Expected return on plan assets	(19,786)	(18,841)	(17,758)
Prior service and other costs	1,278	1,922	1,922
Recognized net actuarial loss	3,508	2,105	904
Amortization of early retirement costs	2,395	2,875	3,241
Qualified-pension expense	$16,812	$15,567	$14,206

Assumptions at the beginning of the year used to calculate pension expense for the year were as follows:

	2005	2004	2003
Discount rate	6.50%	6.75%	7.00%
Rate of increase in compensation	4.00%	4.00%	4.00%
Long-term return on assets	8.25%	8.50%	8.50%

The projected-benefit obligation was measured using a discount rate of 6.0% and 6.5% at December 31, 2005, and 2004, respectively. Changes in discount rates are included in changes in plan assumptions. Asset-return assumptions are based on historical returns tempered for expectations of future performance. The 2006 estimated qualified-pension expense and contribution is $17.5 million.

Qualified Pension Plan	2005	2004
	(in thousands)	
Change in benefit obligation		
Projected benefit obligation at January 1,	$321,744	$292,501
Service cost	8,737	8,077
Interest cost	20,680	19,429
Change in plan assumptions	27,649	12,214
Actuarial loss	2,122	993
Benefits paid	(11,825)	(11,470)
Projected benefit obligation at December 31,	369,107	321,744

Change in plan assets		
Fair value of plan assets at January 1,	232,705	207,109
Actual return on plan assets	18,802	21,499
Contributions to the plan	16,392	15,567
Benefits paid	(11,825)	(11,470)
Fair value of plan assets at December 31,	256,074	232,705
Plan assets less-the-projected benefit obligation	(113,033)	(89,039)
Unrecognized net-actuarial loss	107,227	79,979
Unrecognized prior-service cost	10,361	11,639
Accrued qualified pension cost	4,555	2,579
Accrued nonqualified pension cost	(4,116)	(3,348)
Additional pension liability	(45,073)	(31,871)
Pension liability	($44,634)	($32,640)

The accumulated-benefit obligation for the qualified defined-benefit pension plan was $293.7 million and $258.2 million at December 31, 2005, and 2004, respectively. Estimated pension-plan payments for the five years following 2005 and the subsequent five years aggregated are as follows:

	(in millions)
2006	$11.5
2007	11.9
2008	12.4
2009	13.0
2010	13.8
2011 through 2015	92.0

Nonqualified pension plan

The Company also has a nonqualified pension plan that covers a group of management employees in addition to the qualified pension plan discussed above. The nonqualified pension plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee above the benefit limit defined by the Internal Revenue Service for the qualified plan. The nonqualified pension plan is unfunded. Claims are paid from the Company s general funds.

	Year Ended December 31,		
	2005	2004	2003

Nonqualified pension expense (in thousands)	$2,333	$2,341	$3,009
Benefits paid (in thousands)	$1,533	$1,591	$3,743
Actuarial assumptions:			
Discount rate	6.50%	6.75%	7.00%
Rate of increase in compensation	4.00%	4.00%	4.00%

Nonqualified pension plan

	December 31,	
	2005	2004
	(in millions)	
Accumulated benefit obligation	$7.0	$7.1
Projected benefit obligation	8.4	8.0

Estimated nonqualified pension-plan payments for the five years following 2005 and the subsequent five years aggregated are as follows:

	(in millions)
2006	$2.5
2007	1.1
2008	0.5
2009	0.4
2010	0.3
2011 through 2015	1.7

Postretirement Benefits Other Than Pensions

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 as determined by an employee's years of service and generally limited to 170% of the 1992 contribution for employees who retired after January 1, 1993. The Company is amortizing its transition obligation over a 20-year period, which began in 1992.

A summary of the expense of postretirement benefits other than pensions is listed below. Expenses include an estimate of the effect of the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The drug benefit offered as part of postretirement medical coverage is actuarially equivalent to Part D of Medicare.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Service cost	$ 799	$ 784	$ 787
Interest cost	4,600	5,217	5,303
Expected return on plan assets	(2,955)	(3,049)	(2,602)
Amortization of transition obligation	1,878	1,878	1,877
Amortization of losses	82	321	481
Special-termination benefits		165	
Accretion of regulatory liability	800	800	800
Postretirement benefit expense	$5,204	$6,116	$6,646

Assumptions at the beginning of the year used to calculate postretirement-benefit expense for the year were as follows.

	2005	2004	2003
Discount rate	6.50%	6.75%	7.00%
Long-term return on assets	8.25%	8.50%	8.50%
Health-care inflation rate	8.50%	9.00%	9.50%
	decreasing to	decreasing to	decreasing to
	5.0% by 2011	6.5% by 2009	6.5% by 2009

Service costs and interest costs are sensitive to changes in the health-care inflation rate. A 1% increase in the health-care inflation rate would increase the yearly service and interest costs by $101,000 and the accumulated postretirement-benefit obligation by $1.5 million. A 1% decrease in the health-care inflation rate would decrease the yearly service cost and interest cost by $89,000 and the accumulated postretirement-benefit obligation by $1.4 million.

	2005	2004
	(in thousands)	
Postretirement Benefits Other Than Pensions		

Change in benefit obligation		
Projected benefit obligation at January 1,	$83,686	$81,122
Service cost	799	784
Interest cost	4,600	5,217
Actuarial (gain) loss	(4,061)	1,756
Special termination benefits		165
Benefits paid	(5,053)	(5,358)
Projected-benefit obligation at December 31,	79,971	83,686
Change in plan assets		
Fair value of plan assets at January 1,	38,485	35,866
Actual gain on plan assets	2,975	3,552
Contributions to the plan	3,267	4,425
Benefits paid	(5,053)	(5,358)
Fair value of plan assets at December 31,	39,674	38,485
Projected-benefit obligation in excess of plan assets	(40,297)	(45,201)
Unrecognized-transition obligation	13,142	15,020
Unrecognized net loss	10,740	14,902
Accrued postretirement-benefit cost	($16,415)	($15,279)

Estimated postretirement-benefit payments for the five years following 2005 and the subsequent five years aggregated are as follows:

	(in millions)
2006	$ 4.9
2007	5.0
2008	5.0
2009	5.1
2010	5.1
2011 through 2015	26.9

Postemployment Benefits

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. Assumptions used to calculate postemployment-benefit liability were as follows:

	2005	2004	2003
Postemployment liability at December 31			
(in thousands)	$1,831	$1,521	$1,656
Discount rate	6.00%	6.50%	6.75%
Health-care inflation rate	8.50%	9.00%	9.50%
	decreasing to	decreasing to	decreasing to
	5.0% by 2011	6.5% by 2009	6.5% by 2009

Note 14 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 13.1%. 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 18.1%. 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 21.1%.

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 13.1%.

Wexpro's investment base, net of depreciation and deferred income taxes, and the yearly average rate of return for 2005 and the previous two years are shown in the table below:

	2005	2004	2003
Wexpro s net investment base (in millions)	$206.3	$182.8	$172.8
Average annual rate of return (after tax)	20.4%	19.7%	19.8%

Note 15 Operations by Line of Business

Line of business information is presented according to senior management s basis for evaluating performance including differences in the nature of products, services and regulation. Following is a summary of operations by line of business for the three years ended December 31, 2005:

	Questar Consol.	Interco. Trans.	Questar E & P	Wexpro	Gas Mgt.	Energy Trading	Questar Pipeline	Questar Gas	Corp. and Other
				(in thousands)					
2005									
Revenues									
From unaffiliated customers	$2,724,888		$ 620,610	$ 21,652	$ 141,495	$ 884,913	$ 82,589	$ 956,403	$ 17,226
From affiliated companies		($869,831)		132,305	13,746	632,384	83,393	6,144	1,859
	2,724,888	(869,831)	620,610	153,957	155,241	1,517,297	165,982	962,547	19,085
Operating expenses									
Cost of natural gas and other products sold	1,371,327	(860,172)	4,200			1,501,736		720,173	5,390
Operating and maintenance	262,778	(1,565)	61,790	11,239	85,189	920	30,667	73,834	704

Production and other taxes	120,227		68,682	32,602	709	207	5,764	11,013	1,250
General and administrative	123,055	(1,955)	33,845	9,961	7,528	3,885	25,239	39,252	5,300
Depreciation, depletion and amortization	250,303		134,651	26,864	11,346	909	29,424	45,828	1,281
Pipeline impairment	16,000						16,000		
Exploration	11,538		11,171	367					
Abandonment and impairment of gas, oil and related properties	7,931		7,692	239					
Wexpro oil income sharing		(6,139)		6,139					
Total operating expenses	2,163,159	(869,831)	322,031	87,411	104,772	1,507,657	107,094	890,100	13,925
Operating income	561,729		298,579	66,546	50,469	9,640	58,888	72,447	5,160
Interest and other income	13,702	(34,341)	1,527	789	289	30,131	1,405	4,962	8,940
Income from unconsol. affiliates	7,468		255		7,192	21			
Interest expense	(69,295)	34,341	(23,649)	(121)	(3,058)	(30,246)	(22,326)	(20,158)	(4,078)
Income tax expense	(187,923)		(103,924)	(23,545)	(19,193)	(3,465)	(13,561)	(21,276)	(2,959)
Net income	$ 325,681		$ 172,788	$ 43,669	$ 35,699	$ 6,081	$ 24,406	$ 35,975	$ 7,063
Identifiable assets	$4,357,073		$1,639,192	$ 305,940	$ 301,191	$ 237,709	$ 757,581	$1,090,393	$ 25,067
Investment in unconsol. affiliates	30,681		23		30,331	327			
Capital expenditures	715,886		421,075	57,794	93,277	960	67,422	74,169	1,189
<u>2004</u>									
Revenues									
From unaffiliated customers	$1,901,431		$ 448,706	$ 17,315	$ 87,354	$ 500,479	$ 67,844	$ 759,486	$ 20,247

From affiliated companies		($662,367)	90	115,637	11,589	426,311	88,635	4,707	15,398
	1,901,431	(662,367)	448,796	132,952	98,943	926,790	156,479	764,193	35,645
Operating expenses									
Cost of natural gas and other products sold	821,833	(642,009)	2,232		909	918,681		536,128	5,892
Operating and maintenance	213,573	(6,697)	51,860	11,064	49,899	954	26,280	69,223	10,990
Production and other taxes	90,948		47,102	24,847	1,082	212	6,557	9,767	1,381
General and administrative	114,228	(8,959)	30,641	9,385	6,820	2,860	29,374	35,563	8,544
Depreciation, depletion and amortization	216,175		107,452	25,031	9,446	759	28,235	41,956	3,296
Rate-refund obligation	4,090							4,090	
Exploration	9,239		9,239						
Abandonment and impairment of gas, oil and related properties	15,758		12,968	2,790					
Wexpro oil income sharing		(4,702)		4,702					
Total operating expenses	1,485,844	(662,367)	261,494	77,819	68,156	923,466	90,446	696,727	30,103
Operating income	415,587		187,302	55,133	30,787	3,324	66,033	67,466	5,542
Interest and other income	6,598	(28,302)	988	503	318	25,842	202	3,508	3,539
Income from unconsol. affiliates	5,125		172		4,953				
Interest expense	(68,429)	28,302	(21,679)	(931)	(2,766)	(27,447)	(22,242)	(19,733)	(1,933)
Income tax expense	(129,580)		(58,625)	(19,402)	(12,245)	(816)	(16,397)	(19,780)	(2,315)
Net income	$ 229,301		$ 108,158	$ 35,303	$ 21,047	$ 903	$ 27,596	$ 31,461	$ 4,833
Identifiable assets	$3,674,487		$1,233,912	$ 272,123	$ 204,619	$ 172,054	$ 745,570	$ 989,688	$ 56,521

Investment in unconsol. affiliates	33,229		128		32,639	462			
Capital expenditures	442,483		259,865	38,921	26,308	7,712	30,063	77,040	2,574
<u>2003</u>									
Revenues									
From unaffiliated customers	$1,463,188		$ 343,804	$ 13,004	$ 70,189	$ 324,505	$ 74,981	$ 618,791	$ 17,914
From affiliated companies		($549,887)	90	101,598	10,727	323,212	81,857	2,204	30,199
	1,463,188	(549,887)	343,894	114,602	80,916	647,717	156,838	620,995	48,113
Operating expenses									
Cost of natural gas and other products sold	527,366	(517,213)	2,593		874	641,938		394,523	4,651
Operating and maintenance	205,011	(14,204)	45,547	9,992	45,170	944	23,140	74,224	20,198
Production and other taxes	70,681		31,946	20,479	867	51	6,352	9,743	1,243
General and administrative	94,330	(16,271)	26,461	8,794	5,677	3,287	30,109	26,055	10,218
Depreciation, depletion and amortization	192,382		90,753	20,352	9,272	939	26,141	40,126	4,799
Exploration	4,498		4,498						
Rate-refund obligation	24,939							24,939	
Abandonment and impairment of gas, oil and related properties	4,151		4,151						
Wexpro oil income sharing		(2,199)		2,199					
Total operating expenses	1,123,358	(549,887)	205,949	61,816	61,860	647,159	85,742	569,610	41,109
Operating income	339,830		137,945	52,786	19,056	558	71,096	51,385	7,004
Interest and other income (loss)	7,657	(30,664)	1,098	1,374	(43)	27,834	(426)	3,228	5,256

Income from unconsol. affiliates	5,008		258		4,677	73			
Interest expense	(70,736)	30,664	(20,928)	(2,570)	(2,717)	(29,172)	(22,622)	(20,984)	(2,407)
Income tax expense	(102,563)		(43,420)	(18,385)	(7,640)	319	(17,746)	(13,113)	(2,578)
Net income before accounting change	179,196		74,953	33,205	13,333	(388)	30,302	20,516	7,275
Cumulative effect of accounting change for asset retirement obligations	(5,580)		(4,550)	(563)			(133)	(334)	
Net income	$ 173,616		$ 70,403	$ 32,642	$ 13,333	($ 388)	$ 30,169	$ 20,182	$ 7,275
Identifiable assets	$3,334,195		$ 989,545	$ 244,155	$ 184,668	$193,840	$ 746,542	$ 909,611	$ 65,834
Investment in unconsol. affiliates	36,393		172		35,485	736			
Capital expenditures	325,339		156,087	37,362	31,379	1,933	23,787	71,383	3,408

Note 16 Quarterly Financial and Stock-Price Information (Unaudited)

Following is a summary of quarterly financial and stock-price data:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(dollars in thousands, except per-share amounts)				
2005					
Revenues	$680,324	$520,209	$582,910	$941,445	$2,724,888
Impairment of California segment of Southern Trails				16,000	16,000
Operating income	163,701	108,647	114,325	175,056	561,729
Net income	95,171	60,727	65,757	104,026	325,681
Basic earnings per common share	$1.13	$0.71	$0.78	$1.22	$3.84

Diluted earnings per common share	1.10	0.70	0.75	1.19	3.74
Dividends per common share	$0.215	$0.225	$0.225	$0.225	$0.89
Market price per common share					
High	$62.75	$67.19	$88.78	$89.60	$89.60
Low	46.73	54.49	65.95	70.85	46.73
Close	$59.25	$65.90	$88.12	$75.70	$75.70
Price-earnings ratio on closing price					20.2
Annualized dividend yield on closing price	1.5%	1.4%	1.0%	1.2%	1.2%
Market-to-book ratio on closing price					4.17
Average number of common shares traded per day (000)	566	467	538	742	578
2004					
Revenues	$563,616	$369,515	$360,225	$608,075	$1,901,431
Operating income	136,790	82,297	71,800	124,700	415,587
Net income	76,133	42,556	36,941	73,671	229,301
Basic earnings per common share	$0.91	$0.51	$0.44	$0.88	$2.74
Diluted earnings per common share	0.89	0.50	0.43	0.85	2.67
Dividends per common share	$0.205	$0.215	$0.215	$0.215	$0.85
Market price per common share					
High	$37.08	$38.88	$46.40	$52.12	$52.12
Low	33.82	34.26	37.83	45.00	33.82
Close	$36.44	$38.64	$45.82	$50.96	$50.96
Price-earnings ratio on closing price					19.1
Annualized dividend yield on closing price	2.3%	2.2%	1.9%	1.7%	1.7%
Market-to-book ratio on closing price					2.99
Average number of common shares traded per day (000)	221	225	374	336	290

Note 17 Supplemental Gas and Oil Information (Unaudited)

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

Questar E&P Activities

The following information is provided with respect to Questar E&P s gas and oil exploration and production activities, which are all located in the United States.

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below. Future-abandonment costs associated with asset retirement obligations amounted to $27.5 million and $25.0 million at December 31, 2005 and 2004, respectively. These costs are included in proved properties and support equipment and facilities.

	December 31,	
	2005	2004
	(in thousands)	
Proved properties	$2,047,868	$1,602,143
Unproved properties	41,567	62,678
Support equipment and facilities	18,389	16,932
	2,107,824	1,681,753
Accumulated depreciation, depletion and amortization	731,098	600,366
	$1,376,726	$1,081,387

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 $116.7 million, $80.1 million and $55.3 million in 2005, 2004 and 2003, respectively.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Property acquisition			

Unproved	$13,656	$ 13,346	$ 3,779
Proved	3,421	1,205	1,039
Exploration (capitalized and expensed)	49,305	25,059	13,521
Development	379,232	238,012	155,226
Asset retirement obligations	2,547	1,699	1,616
	$448,161	$279,321	$175,181

Results of Operation

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

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Revenues	$620,610	$448,796	$343,894
Production expenses	130,472	98,962	77,167
Exploration expenses	11,171	9,239	4,498
Depreciation, depletion and amortization	132,288	105,451	88,901
Accretion expense (asset retirement obligations)	2,363	2,001	1,852
Abandonment and impairment of gas, oil and related properties	7,692	12,968	4,151
Total expenses	283,986	228,621	176,569
Revenues less expenses	336,624	220,175	167,325
Income taxes	126,571	77,502	61,409
Results of operation before corporate overhead, interest and cumulative effect of accounting change	210,053	142,673	105,916
Cumulative effect of accounting change for asset retirement obligations			(4,550)
Results of operation before corporate overhead and interest expenses	$210,053	$142,673	$101,366

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of the Company s proved gas and oil reserves have been prepared by Ryder Scott Company, Netherland, Sewell & Associates, Inc. and H. J. Gruy and Associates, Inc., independent reservoir engineers, in accordance with the SEC s Regulation S-X and SFAS 69 Disclosures about Oil and Gas Producing Activities. The table below summarizes the changes in the estimated net quantities of proved natural gas, oil and NGL reserves for each of the three years in the period ended December 31, 2005. The quantities reported are based on existing economic and operating conditions at the time the estimates were made. All gas and oil reserves reported are located in the United States. The Company does not have any long-term supply contracts with foreign governments or reserves of equity investees.

	Natural Gas (MMcf)	Oil and NGL (Mbbl)	Natural Gas Equivalents (MMcfe)[a]
Balance at January 1, 2003	950,406	27,170	1,113,426
Revisions of estimates	14,057	445	16,726
Extensions and discoveries	111,575	1,285	119,285
Purchase of reserves in place	2,098	8	2,146
Sale of reserves in place	(152)	(3)	(170)
Production	(78,811)	(2,324)	(92,755)
Balance at December 31, 2003	999,173	26,581	1,158,658
Revisions -			
Previous estimates	(16,400)	(786)	(21,113)
Pinedale increased-density[b]	302,613	2,383	316,913
Extensions and discoveries	74,155	1,340	82,193
Purchase of reserves in place	812	5	842
Sale of reserves in place	(21)		(21)
Production	(89,801)	(2,281)	(103,488)
Balance at December 31, 2004	1,270,531	27,242	1,433,984
Revisions -			
Previous estimates	11,897	(663)	7,919
Pinedale increased-density[b] [c]	31,457	259	33,005
Extensions and discoveries	110,918	1,395	119,293
Purchase of reserves in place	282	67	681
Sale of reserves in place	(295)	(1)	(301)
Production	(99,959)	(2,375)	(114,206)
Balance at December 31, 2005	1,324,831	25,924	1,480,375
<u>Proved-Developed Reserves</u>			
Balance at January 1, 2003	540,333	19,942	659,985
Balance at December 31, 2003	612,181	20,504	735,205

Balance at December 31, 2004	680,587	21,293	808,345
Balance at December 31, 2005	792,027	21,416	920,523

(a) Natural Gas Equivalents oil volumes are converted to natural gas equivalents using the ratio of one stock tank barrel of crude oil or NGL to 6,000 cubic feet of natural gas.

(b) Estimates of the quantity of proved reserves from the Company s Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling activity, producing well performance and an improved understanding of Lance Pool reservoir characteristics. Analysis of new data has led to progressive increases in estimates of original gas-in-place in the Lance Pool reservoirs at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes.

During the third quarter of 2004, the Company presented detailed reservoir engineering and other data to the Wyoming Oil and Gas Conservation Commission (WOGCC) in conjunction with a request for approval of 20-acre-density development on the Company s Pinedale leasehold. The WOGCC approved the request, and as a result, for the year ended December 31, 2004, the Company reported a net increase of 295 Bcfe of proved reserves at Pinedale. The net increase was comprised of 333 Bcfe of additions categorized as extensions and discoveries of proved reserves less 16 Bcfe of revisions related to removal of certain previously booked proved undeveloped locations as a result of the increased density, further reduced by 23.5 Bcfe of production. The majority of the net increase in proved reserves at Pinedale was due to the WOGCC s approval of 20-acre density development and the associated 20-acre proved undeveloped locations. The Company now realizes it inappropriately categorized these reserve additions in its 2004 Form 10-K as extensions and discoveries. After a review of the SFAS 69 standard, the Company believes that additions to proved reserves associated with increased density at Pinedale should have been categorized as revisions rather than as extensions and discoveries. Accordingly, the table has been revised for 2004 to reflect the appropriate classification. Because of ongoing development of the property, the Company will disclose future revisions to proved reserves associated with Pinedale increased-density drilling separately.

(c) On August 9, 2005, the Company requested and the WOGCC approved 10-acre-density drilling at Pinedale. The Company presented detailed reservoir engineering data derived from core measurements, reservoir pressures, and production performance of 10-acre pilot wells that indicates a substantial increase in the estimated original gas-in-place in the Lance Pool reservoirs. As a result of the new information, the Company now estimates that wells drilled on 20-acre density will only recover about 25% of the estimated original gas-in-place in the Lance Pool reservoirs and that 10-acre-density development will be required over most of the Company s leasehold to maximize the economic recovery of in-place volumes. The area approved for 10-acre-density drilling includes all of the currently estimated productive limits of the Company s Pinedale leasehold. While the Company has commenced 10-acre-density development drilling on its leasehold, estimated proved undeveloped reserves at Pinedale continue to be based on 20-acre density.

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 $7.80 in 2005, $5.50 in 2004 and $5.57 in 2003. The average year-end price per barrel of proved oil and NGL reserves combined was $56.47 in 2005, $40.60 in 2004 and $30.45 in 2003. Year-end production costs, development costs and appropriate statutory income tax rates, with consideration of future tax rates already legislated, were used to compute the future net-cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop booked proved undeveloped reserves are $157.3 million, $172.6 million and $155.3 million in 2006, 2007 and 2008, respectively. At the end of this three-year period the Company expects to have evaluated about 63% of the current 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,		
	2005	2004	2003
	(in thousands)		
Future cash inflows	$11,791,069	$8,090,022	$6,378,076
Future production costs	(2,327,898)	(1,723,128)	(1,403,893)
Future development costs	(725,694)	(663,051)	(338,245)
Future asset retirement obligations	(137,898)	(104,356)	(96,187)
Future income tax expenses	(2,930,318)	(1,854,458)	(1,514,814)
Future net cash flows	5,669,261	3,745,029	3,024,937
10% annual discount to reflect timing of net cash flows	(2,962,189)	(1,984,491)	(1,494,924)
Standardized measure of discounted future net cash flows	$2,707,072	$1,760,538	$1,530,013

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

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Beginning balance	$1,760,538	$1,530,013	$ 899,626
Sales of gas and oil produced, net			

of production costs	(490,138)	(349,834)	(266,726)
Net changes in prices and production costs	1,142,242	(37,786)	820,131
Extensions and discoveries, less related costs	330,382	150,692	235,891
Revisions of quantity estimates	113,339	542,317	33,092
Purchase of reserves in place	3,421	1,205	1,039
Sale of reserves in place	(2,928)	(1,363)	(8,610)
Cost to develop proved undeveloped reserves	116,654	80,066	55,334
Change in future development	(120,303)	(203,574)	(47,886)
Accretion of discount	176,054	153,001	89,963
Net change in income taxes	(440,268)	(28,968)	(345,600)
Change in production rate	41,385	(161,734)	21,091
Other	76,694	86,503	42,668
Net change	946,534	230,525	630,387
Ending balance	$2,707,072	$1,760,538	$1,530,013

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 $9.0 million and $8.8 million at December 31, 2005 and 2004, respectively.

	December 31,	
	2005	2004
	(in thousands)	
Wexpro	$283,853	$253,639

Questar Gas	14,429	16,054
	$298,282	$269,693

Costs Incurred

Costs incurred by Wexpro for cost-of-service gas and oil-producing activities were $57.0 million, including $0.5 million associated with asset retirement obligations in 2005, $43.6 million, including $0.6 million associated with asset retirement obligations in 2004 and $36.6 million, including $0.3 million associated with asset retirement obligations in 2003.

Results of Operation

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

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Revenues			
From unaffiliated companies	$ 21,652	$ 17,315	$ 13,006
From affiliates Note A	132,305	115,637	101,596
Total revenues	153,957	132,952	114,602
Production expenses	49,980	40,613	32,670
Depreciation and amortization	24,717	21,038	20,169
Accretion expense (asset retirement obligations)	2,147	3,993	183
Abandonment and impairment of gas and oil properties	239	2,790	
Exploration	367		
Total expenses	77,450	68,434	53,022
Revenues less expenses	76,507	64,518	61,580
Income taxes	26,801	23,167	22,134
Results of operation before corporate overhead, interest expenses and cumulative effect of accounting change	49,706	41,351	39,446
Cumulative effect of accounting change			

for asset retirement obligations			(563)
Results of operation before corporate overhead and interest expense	$49,706	$41,351	$38,883

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

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

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

	Natural Gas (MMcf)	Oil and NGL (Mbbl)	Natural Gas Equivalents (MMcfe)
Proved Reserves			
Balance at January 1, 2003	419,900	3,739	442,334
Revisions of estimates	24,273	103	24,891
Extensions and discoveries	30,286	187	31,408
Production	(40,088)	(449)	(42,782)
Balance at December 31, 2003	434,371	3,580	455,851
Revisions -			
Previous estimates	4,500	42	4,752
Pinedale increased-density[(a)]	112,655	946	118,331
Extensions and discoveries	18,324	62	18,696
Production	(38,758)	(424)	(41,302)
Balance at December 31, 2004	531,092	4,206	556,328
Revisions-			
Previous estimates	(30,870)	(230)	(32,250)
Pinedale increased-density	7,793	56	8,129
Extensions and discoveries	29,207	250	30,707
Production	(39,951)	(404)	(42,375)
Balance at December 31, 2005	497,271	3,878	520,539

Proved-Developed Reserves

Balance at January 1, 2003	395,821	3,481	416,707
Balance at December 31, 2003	406,144	3,330	426,124
Balance at December 31, 2004	409,194	3,202	428,406
Balance at December 31, 2005	406,608	3,099	425,202

[a]For the year ended December 31, 2004, the Company reported a net increase of 105.0 Bcfe of proved reserves at Pinedale. The net increase was comprised of 120.1 Bcfe of additions categorized as extensions and discoveries of proved reserves less 1.8 Bcfe of revisions related to removal of certain previously-booked proved undeveloped locations as a result of the increased density, further reduced by 11.4 Bcfe of production. The majority of the net increase in proved reserves at Pinedale was due to the WOGCC s approval of 20-acre density development and the associated 20-acre proved undeveloped locations. The Company now realizes it inappropriately categorized these reserve additions in its 2004 Form 10-K as extensions and discoveries. After a review of the SFAS 69 standard, the Company believes that additions to proved reserves associated with increased density at Pinedale should have been categorized as revisions rather than as extensions and discoveries. Accordingly, the table has been revised for 2004 to reflect the appropriate classification. Because of ongoing development of the property, the Company will disclose future revisions to proved reserves associated with Pinedale increased-density drilling separately.

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QUESTAR CORPORATION AND SUBSIDIARIES

Schedule of Valuation and Qualifying Accounts

Column D

Column C

Deductions for

Column A

Description

Column B

Beginning Balance

Amounts charged

to expense

accounts written off and other

Column E

Ending Balance

(in thousands)

Year Ended December 31, 2005

Allowance for bad debts

$6,093

$8,798

($7,223)

$7,668

Allowance for notes

receivable

-

3,184

58

3,242

<u>Year Ended December 31, 2004</u>

Allowance for bad debts

6,694

5,519

(6,120)

6,093

<u>Year Ended December 31, 2003</u>

Allowance for bad debts

7,073

3,686

(4,065)

6,694

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

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

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures.

The Company s Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by the report (the Evaluation Date). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, the Company s disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company, including its consolidated subsidiaries, required to be included in the Company s reports filed or submitted under the Exchange Act. The Company s Chief Executive Officer and Chief Financial Officer also concluded that the controls and procedures were effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company s management including its principal executive and financial officers or persons performing similar functions as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls.

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

Management s Assessment of Internal Control Over Financial Reporting

Questar s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(e). Questar s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2005. The criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework* were used to make this assessment. We believe that the Company s internal control over financial reporting as of December 31, 2005, is effective based on those criteria.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on the next page.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Questar Corporation

We have audited management s assessment, included under Management Assessment of Internal Control Over Financial Reporting , that Questar Corporation maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Questar Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Questar Corporation maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Questar Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Questar Corporation as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders equity, and cash flows for each of the three years in the period ended December 31, 2005 and our report dated February 27, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Salt Lake City, Utah

February 27, 2006

<u>ITEM 9B. OTHER INFORMATION.</u>

There is no information to report in this section.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The information requested in this item concerning Questar s directors is presented in the Company s definitive Proxy Statement under the section entitled Election of Directors and is incorporated herein by reference. A definitive Proxy Statement for Questar s 2006 annual meeting will be filed with the Securities and Exchange Commission.

Information about the Company s executive officers can be found in Item 1 of Part I in this Annual Report.

Information concerning compliance with Section 16(a) of the Exchange Act, is presented in the definitive Proxy Statement for Questar s 2006 annual meeting under the section entitled Section 16(a) Compliance and is incorporated herein by reference.

The Company has a Business Ethics and Compliance Policy (Ethics Policy) that applies to all of its directors, officers (including its Chief Executive Officer and Chief Financial Officer) and employees. Questar has posted the Ethics Policy on its website, www.questar.com. Any waiver of the Ethics Policy for executive officers must be approved only by the Company s Board of Directors. Questar will post on its website any amendments to or waivers of the Ethics Policy that apply to executive officers.

ITEM 11. EXECUTIVE COMPENSATION.

The information requested in this item is presented in Questar s definitive Proxy Statement for the Company s 2006 annual meeting, under the sections entitled Executive Compensation and Election of Directors and is incorporated herein by reference. The sections of the Proxy Statement labeled Committee Report on Executive Compensation and Cumulative Total Shareholder Return are expressly not incorporated into this Annual Report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information requested in this item for certain beneficial owners is presented in Questar s definitive Proxy Statement for the Company s 2006 annual meeting under the section entitled Security Ownership, Principal Holders and is incorporated herein by reference. Similar information concerning the securities ownership of directors and executive officers is presented in the definitive Proxy Statement for the Company s 2006 annual meeting under the section entitled Security Ownership, Directors and Executive Officers and is incorporated herein by reference.

Finally, information concerning securities authorized for issuance under the Company s equity compensation plans as of December 31, 2005, is presented in the definitive Proxy Statement for the Company s 2006 annual meeting under the section entitled Equity Compensation Plan Information and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The information requested in this item for related transactions involving the Company s directors and executive officers is presented in the definitive Proxy Statement for Questar s 2006 annual meeting under the sections entitled Information Concerning the Board of Directors and Certain Relationships Executive Officers.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information requested in this item for principal accountant fees and services is presented in the definitive Proxy Statement for Questar s 2006 annual meeting. under the section entitled Audit Committee Report and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.