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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001 OR

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

Commission File No. 0-30321

OUESTAR MARKET RESOURCES, INC.

(Exact name of registrant as specified in its charter)

State of Utah	87-0287750
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
180 East 100 South P.O. Box 45601, Salt Lake City, Utah	84145-0601
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (801)324-2600

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Common Stock, $1.00 Par Value

SECURITIES REGISTERED PURSUANT TO THE SECURITIES ACT OF 1933:

7 1/2% Notes Due 2011

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

State the aggregate market value of the voting stock held by nonaffiliates of the registrant as of March 1, 2002. $0.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of March 1, 2002: 4,309,427 shares of Common Stock, $1.00 par value. (All shares are owned by Questar Corporation.)

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

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ANNUAL REPORT, 2001

PART I

ITEM 1. BUSINESS.

GENERAL

Questar Market Resources, Inc. (the "Company" or "QMR," which is a reference that includes the Company's subsidiaries) is a wholly owned subsidiary of Questar Corporation ("Questar"), which is a publicly traded and diversified energy services company. Questar has two principal business units--Regulated Services and Market Resources. QMR and its subsidiaries comprise the Market Resources unit of Questar and engage in gas and oil exploration, development and production; gas gathering and processing; wholesale gas and hydrocarbon liquids trading, risk management, natural gas storage, and electric power project development. QMR also buys and sells producing gas and oil properties.

QMR is a subholding company that conducts business through subsidiaries Questar Exploration and Production Company ("Questar E & P"); Celsius Energy Resources, Ltd. ("Celsius"); Shenandoah Energy, Inc. ("SEI"); Wexpro Company ("Wexpro"); Questar Gas Management Company ("QGM"); and Questar Energy Trading Company ("QET"). The corporate organization is shown in the following chart.

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                                   QUESTAR
                                 CORPORATION
                                      |
              ----------------------------------------------------------------------
              |                                  |                                  |
              |                               QUESTAR                            QUESTAR
            QUESTAR                            MARKET                           REGULATED
           INFOCOMM,                         RESOURCES,                         SERVICES
             INC.                               INC.                             COMPANY
         (Information                       (Subholding                       (Subholding
           Services)                          Company)                          Company)
                                                 |                                  |
                                                 |                    --------------------------------
                                                 |                    |                              |
                                                 |               QUESTAR GAS                      QUESTER
                                                 |                 COMPANY                        PIPELINE
                                                 |                 (Retail                         COMPANY
                                                 |              Distribution)                  (Transportation
                                                 |                                              and Storage)
                                                 |
                                                 |
      ----------------------------------------------------------------------------------------------------
      |              |                    |                |                   |                          |
Wexpro Company  Shenandoah             Questar       Celsius Energy     Questar Energy               Questar
 (Manages and   Energy Inc.          Exploration       Resources,       Trading Company                Gas
   Develops     (Exploration        & Production         Ltd.             (Wholesale                Management
Cost-of-Service     and               Company        (Exploration            Energy                   Company
  Properties)   Production,        (Exploration          and               Marketing,               (Gathering
                 Gathering,            and           Production -             Risk                      and
                 Processing)        Production)         Canada)            Management               Processing)
                                                                          and Storage)
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QMR is the primary growth area within Questar's business strategy. Over the next five years, Questar expects to spend 60-70 percent of its total capital budget in QMR's businesses and expects to obtain double-digit growth in earnings from these investments. Future capital investments include ongoing exploration and development drilling on existing properties; possible acquisition of additional producing gas and oil properties; development of new gathering and processing infrastructure, underground gas storage facilities, and electric power generation plants; and continued funding of marketing and risk management activities.

The Company's management believes that growth in its core exploration and production ("E&P") business enhances complementary growth in other QMR subsidiaries. As the E&P entities find or acquire new reserves, QGM should have more opportunities to expand gathering and processing activities, and QET should have more physical production to support its marketing programs and risk management activities.

BUSINESS STRATEGY. QMR has the following strategies in its business:

- pursue a disciplined acquisition and exploitation program that grows reserves and production at attractive finding and development costs;

- expand and exploit a portfolio of quality drilling prospects;

- deliver industry-leading returns on assets and shareholder equity;

- hedge 50 to 75 percent of equity production to meet earnings and growth targets while protecting against downside commodity price risk;

- divest marginal assets and activities;

- maintain a strong balance sheet to fund future acquisitions as opportunities arise;

- evaluate and implement latest proven technology to enhance performance and reduce costs; and

- protect the environment and the health and safety of employees, customers and the communities in which the Company operates.

QMR's activities are described below:

GAS AND OIL EXPLORATION AND PRODUCTION.

Questar's E&P group consists of Questar E&P and its Canadian subsidiary, Celsius, and SEI. These entities pursue a low-risk acquire and exploit strategy focused in three geographic core areas where the Company has accumulated significant expertise - the Rockies, the Midcontinent, and western Canada.

Important areas of activity within the Rockies include the Pinedale Anticline in southwestern Wyoming, where Questar E&P and affiliate Wexpro have recently embarked on an aggressive multi-year drilling program, and the recently acquired SEI properties.

PINEDALE ANTICLINE. At Pinedale Anticline, Questar E&P and Wexpro have approximately 60 percent average working interest in 14,800 acres in the Mesa Area. At year-end 2001, the combined entities had 30 producing wells and five wells actively drilling or awaiting completion. On December 31, 2001, the companies reported combined gross production of approximately 63 MMcfed, compared to 26 MMcfed at year-end 2000. (SEE the Glossary of Commonly Used Gas and Oil Terms on page 57 of this report for abbreviations.)

QMR's success at Pinedale represents its strategy of aggressive application of proven technology to add value. Wexpro originally discovered gas at Pinedale in the early 1970's, but the "tight" nature of the sandstone reservoirs prohibited establishment of economic flow rates. Over the past several decades, steady advances in hydraulic fracture technology and development of

techniques to conduct cost-effective multiple stage stimulations in a single well bore finally unlocked the vast quantities of gas included in these tight sand reservoirs. A typical well at Pinedale, drilled to depths of 13,000 to 15,000 feet, and completed with up to a dozen separate "stages" of fracture stimulation, costs between $2.6 and $3.6 million. Results to date indicate average gross per well reserves of 5 to 6 Bcfe, depending on location.

QMR expects to continue drilling at Pinedale throughout 2002. The area is subject to certain environmental and regulatory restrictions that prohibit or restrict activities during certain times of the year. The current Pinedale development plan, based on 80-acre spacing, will require 135 to 150 wells to fully develop QMR's acreage. The Company continues to assess the feasibility of 40-acre spacing.

SEI. In August 2001, QMR acquired SEI, a privately-held entity engaged in gas and oil drilling and production plus gathering and processing activities in Utah's Uinta Basin, for $403 million in cash and assumed debt. The SEI acquisition added 415 Bcfe of proved reserves (72 percent natural gas and 28 percent oil), 114,000 net acres of undeveloped leasehold acreage, 100 MMcfd of natural gas processing capacity, 90 miles of gathering lines, and four drilling rigs.

The Company anticipates aggressively developing the SEI acreage over the next several years by drilling the large inventory of Wasatch Formation, low-risk tight gas sand development locations. The Wasatch Formation underlies the Green River Formation, which QMR believes contains significant unrecovered oil volumes. Green River reservoirs have been extensively developed and waterflooded by the previous operator of the SEI properties, but low recovery factors indicate significant additional recoverable oil volumes that were not obtained from the reservoirs during the initial waterflood. Wasatch development drilling will allow further evaluation of remaining Green River potential as each wellbore allows a "free look" at the zone in areas around the margins of the existing Green River oil pool that have not been drilled extensively and between existing Green River producers inside the current pool boundaries. The Company will evaluate the results of 2002 drilling to determine the viability of additional Green River oil development.

OTHER AREAS. In the Midcontinent area, Questar E&P is active in the Anadarko and Arkoma basins, the area commonly referred to as "ARK-LA-TEX", and the onshore Gulf Coast basin. And in Canada, Celsius focuses on the intermediate and deeper sections of the Western Canadian Sedimentary Basin in Alberta and British Columbia.

NATURAL GAS FOCUSED. Natural gas remains the primary focus of the Company's E&P operations. As of year-end 2001, the Company had proved reserves (excluding cost-of-service reserves belonging to its affiliate Questar Gas Company ("Questar Gas")) of 998.0 Bcf of gas and 31.1 MMBbls of oil and NGLs, compared to 639.9 Bcf of gas and 15.0 MMbbls of oil and NGLs at the end of 2000. On an energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil, natural gas comprised approximately 84.3 percent of total non-regulated proved reserves. Proved developed reserves constituted 60.8 percent of the total non-regulated proved reserves reported. Approximately 6.2 percent of the group's natural gas proved reserves and 10.7 percent of its proved oil reserves are located in Canada. SEE Note 11 of the Notes to Consolidated Financial Statements under Item 14 of this report for additional information concerning QMR's reserves.

Questar E&P maintains regional offices in Denver, Colorado and Tulsa and Oklahoma City, Oklahoma. SEI has offices in Denver and Vernal, Utah. Canadian operations are managed through an office in Calgary, Alberta.

DEVELOPMENT AND PRODUCTION SERVICES

QMR subsidiary Wexpro develops and produces gas supplies on certain producing properties owned by Questar's retail distribution utility, Questar Gas, in exchange for reimbursement of costs and a specified return on investment in successful gas wells. Wexpro was incorporated as a subsidiary of Questar Gas in 1976 and ownership was transferred to QMR in 1982. Questar Gas's efforts to transfer ownership interest in producing properties and leasehold acreage to Wexpro resulted in protracted regulatory proceedings and legal adjudications that ended with a court-approved settlement agreement that was effective August 1, 1981 ("Settlement Agreement"). A summary of the Settlement Agreement is contained in Note 9 of the Notes to Consolidated Financial Statements under Item No. 14 of this report.

Under the Settlement Agreement, Questar Gas reimburses Wexpro for its costs plus a specified rate of return on its net investment in successful gas wells, adjusted for working capital and deferred taxes. Wexpro's rate of return averaged 19.7 percent on an after-tax basis in 2001. At year-end 2001, Wexpro's investment (net of deferred income taxes) in cost-of-service operations was $161.3 million compared to $124.8 million at year-end 2000. Wexpro does not conduct exploratory operations nor acquire leasehold acreage for exploration activities. Under the terms of the Settlement Agreement, Wexpro bears all dry hole costs. The Settlement Agreement is monitored by the Utah Division of Public Utilities, the staff of the Public Service Commission of Wyoming and experts retained by these agencies.

The gas volumes developed and produced by Wexpro for Questar Gas are reflected in the latter's rates at cost-of-service prices. Cost-of-service gas (defined to include the gas attributable to royalty interest owners) produced by Wexpro satisfied 44 percent of Questar Gas's system requirements during 2001. During 2001, the average wellhead cost of Questar Gas's cost-of-service gas was

$2.55 per Dth, which is lower than Questar Gas's average price for field-purchased gas.

Wexpro participates in drilling activities in response to the demands of other working interest owners, to protect its rights, and to meet the needs of Questar Gas. In 2001, Wexpro produced 41.0 Bcfe of natural gas and hydrocarbon liquids from Questar Gas's cost-of-service properties and added 69.1 Bcfe of reserves through drilling activities and reserve estimate revisions. These numbers do not include related royalty gas.

Wexpro, under the terms of the Settlement Agreement, also owns oil-producing properties. The revenues from the sale of crude oil produced from such properties are used to recover operating expenses and provide Wexpro with a return on its investment. In addition, Wexpro receives 46 percent of any residual income. The remaining income is received by Questar Gas and used to reduce natural gas costs reflected in customer rates. Wexpro also has an ownership interest in the wells and facilities related to its oil properties and in the wells and facilities that have been installed since August 1, 1981 to develop and produce certain gas properties.

Wexpro maintains an office in Rock Springs, Wyoming, in addition to its principal office in Salt Lake City, Utah.

GATHERING, PROCESSING, POWER DEVELOPMENT, MARKETING AND RISK MANAGEMENT.

QGM conducts gathering and processing activities in the Rocky Mountain and Midcontinent areas. QGM's activities are not subject to regulation by the Federal Energy Regulatory Commission (the "FERC") because the Natural Gas Act of 1938 specifically provides that the FERC's jurisdiction does not extend to facilities involved in the production or gathering of natural gas.

Most of QGM's gathering system in the Rockies was originally built to gather production from Questar Gas's cost-of-service properties as part of a regulated enterprise. The system includes gathering lines, compressor stations, field dehydration plants and measuring stations. Under a contract that was assigned when the gathering assets were transferred from Questar Pipeline, QGM is obligated to gather the cost-of-service production for the life of the properties. During 2001, QGM gathered 37.2 MMDth of natural gas for Questar Gas, compared to 36.8 MMDth in 2000. QGM also gathers gas for QMR affiliates and for nonaffiliated customers. During 2001, QGM gathered 27.0 MMDth for QMR affiliates, compared to 25.0 MMDth in 2000, and gathered 91.7 MMDth for nonaffiliated customers, compared to 93.0 MMDth in 2000.

During 2001, QGM formed a new joint venture--Rendezvous Gas Services ("Rendezvous")-- with Western Gas Resources ("Western Gas"), to develop and operate new gathering and compression facilities in the Hoback Basin of southwestern Wyoming. QGM and Western Gas each own 50 percent of Rendezvous. The Hoback Basin is the site of increased industry activity including recent prolific discoveries by Questar E&P and Wexpro at Pinedale Anticline. Gas reserves from more than 179,000 gross acres are dedicated to Rendezvous under existing gathering contracts. The Rendezvous system will deliver gas from new development activities along the Pinedale Anticline and adjacent areas for processing and blending at the Blacks Fork plant in which QGM has a 50 percent interest and at Rendezvous will also deliver gas volumes to the nearby Granger plant owned by an affiliate of Western Gas.

The year also witnessed a functional combination of QGM's gathering facilities in eastern Utah with SEI's gathering assets. SEI's eastern Utah assets include 90 miles of gas gathering lines and the 100 MMcfd Red Wash plant.

QGM is also involved in gas processing. A gas processing plant strips hydrocarbon liquids including ethane, propane, butane and gasoline (collectively NGLs) from the raw natural gas stream. Typically, NGLs are also more valuable to producers as separate commodities than they are when sold as part of the natural gas stream. Gas processing also enables producers to meet gas-quality specifications of interstate pipelines. QMR owns 50 percent of the Blacks Fork gas processing plant, which has a current capacity of 84 MMcfd and is readily expandable as new production volumes are gathered on the Rendezvous system. QGM and Wexpro jointly own a 43 MMcfd processing facility located in the Canyon Creek area of southwestern Wyoming. QGM also owns interests in other processing plants in the Rockies and Midcontinent areas.

QET conducts energy marketing and risk management activities for QMR. It combines QMR equity production with gas volumes purchased from third parties to build a flexible and reliable portfolio. QET aggregates supplies of natural gas for delivery to large customers, including industrial users, municipalities, and other marketing entities. During 2001, the Company marketed a total of 91.8 EMMDth of natural gas and earned a margin of $.149 per equivalent Dth. (The volumes and margins exclude affiliated production.)

QET also executes hedges on equity production for various QMR affiliates and on certain marketing transactions. QET does not engage in speculative hedging transactions. SEE Notes 1 and 5 to Consolidated Financial Statements included in Item 14 of this report for additional information relating to hedging activities.

As a wholesale marketing entity, QET concentrates on markets in the Pacific Northwest, Rocky Mountains, Midwest, and western Canada that are close to reserves owned by affiliates or accessible by major pipelines. It has contracted for firm-transportation capacity on pipelines and firm-storage capacity at the Clay Basin storage facility owned by its affiliate Questar Pipeline Company ("Questar Pipeline").

QET, through a limited liability company in which it has a 75 percent interest, operates the Clear Creek storage facility located in southwestern Wyoming. Clear Creek has 8 Bcf of gross capacity and is connected to pipelines owned by affiliates Questar Pipeline and Overthrust Pipeline Company ("Overthrust"), and by The Williams Companies. A pipeline connection with the Kern River pipeline is planned for 2002.

QET is also charged with development of an electric power generation strategy for Questar. QET's strategy is to pursue power generation opportunities in western states that are complementary to Questar's pipeline, gas storage and production assets. While near-term market fundamentals for new power project developments are weak, QET believes it has identified several projects that are well-positioned to take advantage of increasing demand for power in the western United States in the intermediate term. QET will only invest in power projects supported by long-term power purchase agreements with creditworthy counterparties.

QET is in the final stages of negotiating a possible marketing alliance with a major energy marketing company. The first phase will be a pilot project in which QET will assign storage contracts to the alliance. QET will provide physical market support and market intelligence, and the merchant partner will manage commercial activities. This pilot will allow QET to assess the benefits and risks of expanding its marketing and risk management activities either alone or in conjunction with a strategic partner. QET anticipates finalizing the agreement for the first phase within the first quarter of 2002.

QGM and QET both maintain offices in Salt Lake City, Utah.

REGULATION

The Company's operations are subject to various levels of government controls and regulation in the United States and Canada at the federal, state/provincial, and local levels. Such

regulation includes requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; submitting and implementing spill prevention plans; submitting notices relating to the presence, use and release of specified contaminants incidental to gas and oil regulations; and regulating the location of wells, the method of drilling and casing wells, surface usage and restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transportation of production. QMR's operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, and the unitization or pooling of gas and oil properties. State conservation laws establish the maximum rates of production from gas and oil wells, generally prohibit the venting or flaring of gas, and impose certain requirements for the ratable purchase of production.

Some of QMR's leases, including many of its leases in the Rocky Mountain area, are granted by the federal government and administered by federal agencies. These leases require compliance with detailed financial regulations on such things as drilling and operations on the leases and the calculation and payment of royalties.

Various federal, state and local environmental laws and regulations affect the Company's operations and costs. These laws and regulations concern the generation, storage, transportation, disposal or discharge of contaminants into the environment and the general protection of public health, natural resources, wildlife, and the environment. They also impose substantial liabilities for any failure on the part of the Company to comply with them.

Each province in Canada and the federal government of Canada also have laws and regulations governing land tenure, royalties, production rates and taxes, and environmental protection.

COMPETITION AND CUSTOMERS

QMR faces competition in all aspects of its business including the acquisition of reserves and leases; obtaining goods, services, and labor; and marketing its production. The Company's competitors include multinational energy companies and other independent producers, many of which have greater financial resources than QMR.

QMR's business activities can be subject to seasonal variations. Historically, the demand for natural gas decreases during the summer months and increases during the winter months. The increasing demand for natural gas to generate electricity may cause increased demand during the hottest months of the summer. Weather (both in terms of temperatures and moisture) can have dramatic impacts on natural gas prices and the Company's operations.

The Company sells its natural gas production to a variety of customers including pipelines, gas marketing firms, industrial users, and local distribution companies. QMR's crude volumes are sold to refiners, remarketers and other companies, some of which have pipeline facilities near the producing properties. In the event pipeline facilities are not available, crude oil is trucked to storage, refining, or pipeline facilities.

RELATIONSHIPS WITH AFFILIATES

The subsidiaries of QMR have important relationships with their affiliates as described above. Questar provides certain administrative services, e.g., public and government relations, financial and audit, to QMR and other members of the consolidated group. Questar, as a general rule, also sponsors the qualified and welfare plans in which QMR's employees participate. (Some QMR entities have chosen not to participate in all of the benefit plans sponsored by Questar.) Each of the Company's subsidiaries is responsible for a proportionate share of the costs associated with these services and benefit plans.

EMPLOYEES

As of December 31, 2001, QMR had 581 employees in the United States, compared to 412 at year-end 2000. This increase is attributable to the acquisition of SEI. (Canadian operations are handled through leased employees.) None of these employees is represented under collective bargaining agreements. Employee relations are generally deemed to be satisfactory. QMR also periodically engages independent consulting petroleum engineers, environmental professionals, geologists, geophysicists, landmen and attorneys on a fee basis.

ITEM 2. PROPERTIES.

RESERVES. The following table sets forth the Company'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, 2001. QMR's reserves were collectively estimated by Ryder Scott Company; H. J. Gruy and Associates, Inc.; Netherland, Sewell & Associates, Inc.; Malkewicz Hueni Associates, Inc.; Gilbert Laustsen Jung Associates Ltd.; and Sproule Associates, Ltd., independent petroleum engineers. The Company does not have any long-term supply contracts with foreign governments, or reserves of equity investees or of subsidiaries with a significant minority interest. These proved reserve volumes do not include cost-of-service reserves managed and developed by Wexpro for Questar Gas.

DECEMBER 31, 2001	UNITED STATES	CANADA	TOTAL
Estimated proved reserves			
Natural gas (Bcf)	936.2	61.8	998.0
Oil and NGL (MMBbls)	27.8	3.3	31.1
Total proved reserves (Bcfe)	1,102.6	81.8	1,184.4
Proved developed reserves (Bcfe)			

	651.3	68.4	719.7
Estimated future net revenues before future income taxes (in thousands) (1)	$ 1,477,188	$130,698	$ 1,607,886
Standardized measure of discounted net cash flows (in thousands) (2)	$ 548,160	$ 56,142	$ 604,302

(1) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, 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 net cash flows prepared by the Company represent the present value of estimated future net revenues after income taxes, discounted at 10 percent.

Estimates of the Company's proved reserves and future net revenues are made using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation). Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating natural gas and oil reserves and their estimated values, including many factors beyond the control of the producer. The reserve data set forth in this document are estimates.

Reference should be made to Note 12 of the Notes to Consolidated Financial Statements included in Item 14 of this report for additional information pertaining to the Company's proved natural gas and oil reserves as of the end of each of the last three years.

The Company will file estimated reserves as of December 31, 2001, with the Energy Information Administration in the Department of Energy on Form EIA-23. Although QMR uses the same technical and economic assumptions when it prepares the EIA-23, it is obligated to report reserves for wells it operates, not for all wells in which it has an interest, and to include the reserves attributable to other owners in such wells.

The following charts illustrate QMR's reserve statistics for the years ended December 31, 1997 through 2001:

GAS AND OIL RESERVES (BCFE)*

YEAR	YEAR-END RESERVES	ANNUAL PRODUCTION	RESERVE LIFE(YEARS)
1997	469.3	61.7	7.6
1998	574.1	65.3	8.8
1999	597.6	76.6	

7.8 2000
730.1 82.3
8.9 2001
1,184.4
85.6 13.8

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

Proportion of Proved Developed to Proved Reserves
and Proportion of Gas ReseresS (Bcfe)*

Year	Total Proved Reserves	Proved Developed Reserves	Developed Percentage of Reserves	Natural Gas Percent of Total Proved Reserves
1997	469.3	392.9	84%	81%
1998	574.1	506.0	88%	85%
1999	597.6	503.9	84%	86%
2000	730.1	566.4	78%	88%
2001	1,184.4	719.7	61%	84%

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

GEOGRAPHIC DIVERSITY OF PRODUCING PROPERTIES

The following table summarizes proved reserves by the Company's major operating areas at December 31, 2001:

	PROVED RESERVES* (Bcfe)	PERCENT OF TOTAL
Midcontinent	290	24%
Rocky Mountain Region (exclusive of Pinedale and Uinta Basin)	156	13%
Pinedale Anticline	187	16%
Uinta Basin	469	40%
Western		

Canada 82
7%

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

PRODUCTION. The following table sets forth the Company's net production volumes, the average sales prices per Mcf of gas, Bbl of oil and Bbl of NGLs produced, and the production cost per Mcfe for the years ended December 31, 2001, 2000, and 1999, respectively:

	Year Ended December 31, 2001	2000	1999
UNITED STATES (EXCLUDING COST OF SERVICE ACTIVITIES)			
Volumes produced and sold			
Gas (Bcf)	63.9	61.7	59.8
Oil and NGL (MMBbls)	1.8	1.5	1.9
Sales Prices:			
Gas (per Mcf)	$ 3.21	$ 2.80	$ 2.02
Oil and NGL (per Bbl)	$ 18.14	$ 19.61	$ 13.31
Production costs per Mcfe	$ .84	$ .69	$ .59

CANADA			
Volumes produced and sold			
Gas (Bcf)	6.7	7.3	2.9
Oil and NGL (MMBbls)	.7	.7	.4
Sales Prices:1			
Gas (per Mcf)	$ 3.25	$ 2.83	$ 1.61
Oil and NGL (per Bbl)	$ 21.98	$ 22.29	$ 16.56
Production costs per Mcfe1	$ .74	$ .75	$ .67

(1)In United States dollars.

PRODUCTIVE WELLS. The following table summarizes the Company's productive wells as of December 31, 2001:

PRODUCTIVE WELLS (1) (2)

GAS WELLS
OIL WELLS
TOTAL WELLS

	GROSS	NET	GROSS	NET	GROSS	NET
United States	3,762	1,685	980	529	4,742	2,214
Canada	548	182	186	60	734	242
Total:	4,310	1,867	1,166	589	5,476	2,456

(1) Although many of the Company's wells produce both gas and oil, a well is categorized as either a gas well or an oil well based upon the ratio of gas to oil production.

(2) Each well completed to more than one producing zone is counted as a single well. There were 98 gross wells with multiple completions.

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

LEASEHOLD ACREAGE. The following table summarizes developed and undeveloped leasehold acreage in which the Company owns a working interest as of December 31, 2001. "Undeveloped Acreage" includes (i) leasehold interests that already may have been classified as containing proved undeveloped reserves; and (ii) unleased mineral interest acreage owned by the Company. Excluded from the table is acreage in which the Company's interest is limited to royalty, overriding royalty, and other similar interests.

Leasehold Acreage - December 31, 2001

	DEVELOPED (1)		UNDEVELOPED (2)		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
UNITED STATES						
Arizona	-	-	480	450	480	

450
Arkansas
37,729
16,569
1,918 754
39,647
17,323
California
785 265
13,733
6,015
14,518
6,280
Colorado
176,073
126,112
221,242
110,397
397,315
236,509
Idaho - -
44,175
10,643
44,175
10,643
Illinois
172 39
14,307
3,997
14,479
4,036
Indiana - -
1,621 467
1,621 467
Kansas 134
134 16,000
3,772
16,134
3,906
Kentucky -
- 14,461
5,468
14,461
5,468
Louisiana
15,246
9,992 1,523
1,432
16,769
11,424
Michigan -
- 6,200
1,266 6,200
1,266
Minnesota -
- 313 104
313 104
Mississippi
4,548 2,597
1,485 680
6,033 3,277
Montana
25,285
10,187
319,584
58,434
344,869
68,621
Nevada 320
280 680 543
1,000 823
New Mexico
85,220
62,284
37,242
14,790
122,462
77,074
North
Dakota
1,333 375
145,841
21,580
147,174
21,955 Ohio
- - 202 43

202 43
Oklahoma
1,477,522
263,249
45,387
32,989
1,522,909
296,238
Oregon - -
43,869
7,671
43,869
7,671 South
Dakota - -
204,558
107,988
204,558
107,988
Texas
155,248
52,838
60,294
46,380
215,542
99,218 Utah
84,712
67,712
287,304
141,276
372,016
208,988
Washington
- - 26,631
10,149
26,631
10,149 West
Virginia
969 115 - -
969 115
Wyoming
228,721
143,537
459,416
268,021
688,137
411,558 ---
------ ----
--- -------
-- -------
--------- -

Total U.S.
2,294,017
756,285
1,968,466
855,309
4,262,483
1,611,594 -
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---- ------
- ---------

CANADA
Alberta
238,975
88,305
286,745
108,861
525,720
197,166
British
Columbia
33,331
8,237
33,798
12,865
67,129
21,102
Saskatchewan
2,011 912
3,107 3,107
5,118 4,019
--------- -
------ ----
----- -----

-- --------
- ---------
Total
Canada
274,317
97,454
323,650
124,833
597,967
222,287 ---
------ ----
--- -------
-- -------
--------- -

Total
Acreage
2,568,334
853,739
2,292,116
980,142
4,860,450
1,833,881 -
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- ---------
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(1) Developed acres are acres 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. Of the

aggregate 2,292,116 gross and 980,142 net undeveloped acres, 107,361 gross and 29,939 net acres are held by production from other leasehold acreage.

Substantially all the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed or production has been obtained from the acreage subject to the lease prior to that date, in which event the lease will remain in effect until the cessation of production. 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:

	ACRES EXPIRING	
Twelve Months Ending	GROSS	NET
December 31, 2002	107,577	47,127
December 31, 2003	159,531	72,679
December 31, 2004	133,487	64,276
December 31, 2005	90,320	56,041
December 31, 2006 and later	1,801,201	740,019

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

	YEAR ENDED DECEMBER 31,					
	2001		2000		1999	
	GROSS	NET	GROSS	NET	GROSS	NET
DEVELOPMENT WELLS						
United States						
Completed as natural gas wells	238	110.4	211	79.8	159	78.4
Completed as oil wells	13	9.6	9	1.4	5	2.4
Dry holes	11	4.3	12	5.0	15	6.1
Waiting on completion	46	-	36	-	29	-
Drilling	10	-	14	-	6	-
Canada						
Competed as natural gas wells	7	1.8	11	1.1	7	1.2
Completed as oil wells	2	.5	8	2.3	5	1.9
Dry holes	1	.1	2	1.1	2	1.3
Waiting on completion	-	-	2	-	2	-
Drilling	-	-	1	-	-	-
Total Development Wells	328	126.7	306	90.7	230	91.3

EXPLORATORY WELLS						
United States						
Completed as natural gas wells	1	.4	-	-	1	0.2
Completed as oil wells	-	-	-	-	-	-

Dry holes	1	.4	5	2.0	2	1.1
Waiting on completion	-	-	-	-	1	-
Drilling	-	-	1	-	1	-
Canada						
Competed as natural gas wells	1	.5	1	.2	-	-
Completed as oil wells	1	.4	1	.2	-	-
Dry holes	5	1.9	2	.9	-	-
Total Exploratory Wells	9	3.6	10	3.3	5	1.3
Total Wells	337	130.3	316	94.0	235	92.6

OPERATION OF PROPERTIES. The day-to-day operations of gas and oil properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions. The charges under operating agreements customarily vary with the depth and location of the well being operated.

QMR is the operator of approximately 50 percent of its wells. As operator, QMR receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area to or by unaffiliated third parties. In presenting its financial data, the Questar E&P group records the monthly overhead reimbursement as a reduction of general and administrative expense, which is a common industry practice. Wexpro records the reimbursement as a reduction of operating and maintenance expenses subject to the Settlement Agreement.

TITLE TO PROPERTIES. Title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the gas and oil industry, liens for current taxes not yet due and, in some instances, to other encumbrances. The Company believes that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Investigations, generally including a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

ITEM 3. LEGAL PROCEEDINGS.

There are various legal proceedings pending against QMR and its affiliates. Management believes that the outcome of these cases will not have a material adverse effect on the Company's financial position or liquidity. Significant cases are discussed below.

GRYNBERG. Questar affiliates, including Questar E&P, are named defendants in a lawsuit filed by an independent producer (Grynberg) under the Federal False Claims Act. This case is substantially similar to cases filed by Grynberg against pipelines and their affiliates that have all been consolidated for discovery and pre-trial motions in Wyoming's federal district court. The cases involve allegations of industry-wide mismeasurement and undervaluation of gas volumes on which royalty payments are due the federal government. The complaint seeks treble damages and imposition of civil penalties. The federal district judge denied the motions filed by the defendants to dismiss the lawsuits, but has not yet set a date for a scheduling conference.

A second Grynberg lawsuit is currently on appeal before the Utah Supreme Court. The case was dismissed by a Utah state court judge when he granted the motion for summary judgment filed by the Questar parties. Grynberg claims that QGM, QET, and Questar Pipeline mismeasured gas volumes attributable to his working interest in specified wells located in southwestern Wyoming. He cites mismeasurement to support claims for breach of contract, negligent misrepresentation, fraud, breach of fiduciary responsibilities and related cases.

GAS PIPELINES. Questar E&P, QGM, Wexpro, and other Questar defendants are among the numerous defendants in this case, which is currently styled as WILL PRICE V. GAS PIPELINES, but was formerly known as QUINQUE OPERATING COMPANY V. GAS PIPELINES. Pending in a Kansas state district court, this case is similar to the cases filed by Grynberg, but the allegations of a conspiracy by the pipeline industry to set standards that result in the system mismeasurement of natural gas volumes and resulting underpayment of royalties are made on behalf of private and state lessors, rather than on behalf of the federal government. The defendants, including the Questar defendants, have filed motions to dismiss for lack of personal jurisdiction.

DEQ. Company subsidiaries have received notices of violation from the Wyoming Department of Environmental Quality ("DEQ") in conjunction with DEQ's program to require that all existing air_emission facilities be registered and permitted. QMR has raised an issue concerning DEQ's failure to provide proper notice of the new requirements and contends that existing equipment should be "grandfathered" under DEQ's regulatory program in place at time of installation. The Company expects that any penalties assessed its subsidiaries will not exceed $300,000 on an aggregate basis. The penalties are assessed on a per_well or per_facility basis and differ based on the eligibility of the facility for a waiver or the need for appropriate action to minimize emissions. In response to the action taken by the DEQ, QMR has made an extensive review of wells and other facilities in Wyoming to ascertain that the necessary filings have been made and has established procedures to make such filings on an ongoing basis.

SAMSON. Questar E&P is the named defendant in this case, which is pending in a federal district court in Oklahoma. The case involves claims that Questar E&P, as the operator of a Texas well, failed to attribute to Samson Resources Company its proportionate share of the non-consent

working and revenue interest for the well. The trial court judge granted Samson's motion for partial summary judgment by ruling that Samson should be credited with an 18 percent working interest, which is valued at approximately $1.2 million. The trial scheduled to begin in May will consider Samson's claims for conversion and unspecified punitive damages.

ROYALTY CLASS ACTION CASES. Royalty class actions are being increasingly asserted by landowners against entities involved in the gas and oil production and marketing businesses. QMR entities have been involved in one major class action (the Bridenstine case) that was settled near the end of 2000, reached an agreement to settle another Oklahoma case that was recently filed and obligating it to pay approximately $1.1 million, and been named in class actions in Wyoming, which have yet to be certified.

Some royalty owners are claiming that they are entitled to payments calculated on the final end-use value of gas volumes, rather than on leasehold sale prices for such volumes, particularly when sales are made to affiliates. QMR believes that it will continue to be subject to royalty class actions.

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

The Company did not submit any matters to a vote of its sole stockholder during the last quarter of 2001.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

All of the Company's outstanding shares of common stock, $1.00 par value, are owned by Questar. Information concerning the dividends paid on such stock and the ability to pay dividends is reported in the Statements of Common Shareholder's Equity and the Notes to Financial Statements included in Item 14 of this report.

ITEM 6. SELECTED FINANCIAL DATA.

The Company, as the wholly owned subsidiary of a reporting company under the Securities and Exchange Act of 1934, as amended, (the "Act"), is entitled to omit the information requested in this Item.

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

RESULTS OF OPERATIONS

QUESTAR MARKET RESOURCES ("QMR" or "Market Resources" or the "Company") conducts exploration and production, gas development, gathering, processing and marketing activities.

Questar Market Resources' net income rose 30% in 2001 compared with 2000 driven by a 53% increase in earnings from exploration and production operations and a 16% increase in Wexpro's earnings from gas-development operations. In 2001, gas and oil reserves grew 62% after production to nearly 1.2 trillion cubic feet equivalent.

On July 1, 2001, QMR elected to change its accounting method for gas and oil properties from the full cost method to the successful efforts method. Prior years financial statements were restated in an amended Form 10-K filed for the year ended December 31, 2000. Previously reported earnings decreased $7.2 million and $2.0 million for the years ended December 31, 2000 and 1999, respectively.

Following is a summary of financial results and operating information.

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
OPERATING INCOME			
Revenues			
Natural gas sales	$226,656	$193,359	$125,245
Oil and natural gas liquids sales	59,482	59,901	41,521
Cost-of-service gas operations	89,934	74,492	61,705
Energy marketing	337,845	379,760	243,296
Gas gathering and processing	26,776	29,278	22,341
Other	5,704	5,263	4,203
Total revenues	746,397	742,053	498,311
Operating expenses			
Energy purchases	324,124	369,752	239,201
Operating and maintenance	112,087	106,761	79,719
Exploration	6,986	7,917	5,321
Depreciation, depletion and amortization	92,678	85,025	73,028
Abandonment and impairment of oil and gas properties	5,171	3,418	7,535
Production and other taxes	43,125	36,262	21,516
Wexpro settlement agreement - oilincome sharing	2,885	4,758	2,292
Total operating expenses	587,056	613,893	428,612
Operating income	$159,341	$128,160	$ 69,699

Year Ended December 31,	2001	2000	1999
OPERATING STATISTICS			
Production volumes			
Natural gas (in MMcf)	70,574	68,963	62,712
Oil and natural gas liquids (in Mbbl)			
Questar E & P, SEI	2,500	2,225	2,311
Wexpro	467	521	555
Production revenue			
Natural gas (per Mcf)	$3.21	$2.80	$2.00
Oil and natural gas liquids (per bbl)			
Questar E & P, SEI	$19.22	$20.50	$13.92
Wexpro	$24.49	$27.43	$16.84
Wexpro investment base, net of deferred income taxes (in millions)	$161.3	$124.8	$108.9
Energy-marketing volumes (in thousands of equivalent dth)	91,791	105,632	112,982
Natural gas-gathering volumes (in Mdth)			
For unaffiliated customers	91,729	92,969	84,961
For Questar Gas	37,161	36,791	32,050
For other affiliated customers	27,049	25,068	19,659
Total gathering	155,939	154,828	136,670
Gathering revenue (per dth)	$0.13	$0.13	$0.15

REVENUES
Revenues were 1% higher in 2001 when compared with 2000 as a result of increased production, higher gas prices and increased investment in gas-development activities. Market Resources produced 85.6 billion cubic feet equivalent (Bcfe) in 2001 compared with 82.3 Bcfe in 2000 due to the acquisition of Shenandoah Energy Inc. (SEI) on July 31, 2001, excluding Wexpro. Gas production increased 2% over year earlier levels while average realized selling prices rose 15%. Production of oil and natural gas liquids (NGL) rose 12%, excluding Wexpro. Energy-marketing volumes dropped 13% in 2001 compared with 2000. In 2001, declining prices for plant products and higher gas prices were responsible for reduced revenues and lower margins from processing plants.

Market Resources hedges its gas and oil production to support earnings targets and to protect earnings from downward moves in commodity prices. In 2001, approximately 59% of equity gas production and 58% of oil production, excluding Wexpro, was hedged. This compares with 2000 when approximately 53% of gas production and 73% of oil production was priced under hedging contracts. In 2001, the average price received from hedging transactions was $2.99 per Mcf of gas, net to the well, and $18.28 per barrel of oil, net to the well. Hedging activities reduced 2001 revenues from gas sales by $44.7 million and oil sales by $9.8 million.

Revenues from cost-of-service operations were 21% higher in both 2001 and 2000 when compared with prior years. Wexpro operates and develops oil and natural gas properties on behalf of Questar Gas and receives a return on its investment in successful wells in addition to being reimbursed for operating expenses. The natural gas produced from these properties is delivered to Questar Gas at Wexpro's cost of service. Oil is sold at market prices. Any net income from oil sales remaining after recovery of expenses and Wexpro's return on investment is shared between Wexpro and Questar Gas. Questar Gas' portion is reported as oil-income sharing on the income statement. Wexpro's investment base, net of deferred income taxes, grew 29% and 15% in 2001 and 2000, respectively. The return on average investment base was 19.7% in 2001 and 19.5% in 2000.

Revenues increased 49% in 2000 when compared with 1999 due primarily to higher energy prices and increased gas production. Natural gas prices began rising in the second half of 2000 and spiked in the first quarter of 2001 due to an energy shortage in the western United States. Natural gas production rose 10% as a result of acquiring Canadian producing properties in January 2000.

OPERATING EXPENSES

Operating and maintenance (O&M) expenses were 5% higher in 2001 when compared with 2000 due primarily to an increase of the number of gas and oil properties operated following the acquisition of SEI. O&M expenses increased 34% in 2000 compared with 1999 due primarily to an increase in the number of gas and oil properties and to the costs of litigating and settling a major lawsuit. Exploration expense, largely a function of drilling dry exploratory wells, decreased 12% in 2001 after increasing 49% in 2000. Depreciation, depletion and amortization expense (DD&A) increased 9% in 2001 due to a 4% increase in gas and oil production and a higher average rate. The average DD&A rate for oil and gas properties was $.83 per thousand cubic feet equivalent (Mcfe) for 2001, up from $.78 per Mcfe in 2000 and $.71 per Mcfe in 1999. Production and other taxes rose 19% in 2001 and 69% in 2000 driven by higher revenues and prices. Production costs per Mcfe, which include direct O&M and production-related taxes for producing properties, averaged $.83, $.70 and $.59 for 2001, 2000 and 1999, respectively.

ENRON EXPOSURE

A QMR energy-marketing affiliate has bought and sold natural gas and engaged in energy trading activities with affiliates of Enron. At the time of Enron's announced plan and filing to seek protection under bankruptcy laws, Enron owed QMR $3.0 million for gas purchased from QMR and QMR owed Enron $.8 million for gas purchased from Enron. In addition, QMR owed $.8 million to Enron in a terminated swap contract. It is the opinion of QMR's counsel that these transactions may be netted. QMR has reserved the net amount of these balances or $1.4 million.

INTEREST AND OTHER INCOME

Interest and other income was 109% higher in the 2001 compared with 2000 due to a $13.9 million pre-tax gain as a result of selling non-strategic producing properties and gas-gathering facilities. Interest and other income in 2000 included a $1.7 million pre-tax net gain from selling securities available for sale and properties, capitalized financing costs associated with an underground storage project of $1.9 million and $1.4 million of interest earned on qualifying hedging collateral. Gains from selling non-strategic producing properties amounted to $4 million in 1999, while sales of securities available for sale generated a $.4 million pre-tax gain.

DEBT EXPENSE

Interest expense was flat in 2001 compared with 2000. While QMR significantly increased its debt load to finance the acquisition of SEI, short-term interest rates were the lowest in recent history. The base rate for short-term loans, the one-month LIBOR rate, declined from 6.5% in January 2001 to 1.9% in January 2002. The increase in interest expense in 2000 compared with 1999 was due to higher short- and long-term borrowing balances and higher interest rates in 2000.

INCOME TAXES

The effective combined federal, state and foreign income tax rate was 34.9% in 2001, 33.2% in 2000 and 28.5% in 1999. Income tax rates were below the combined income rate of about 40% primarily due to non-conventional fuel credits, which amounted to $5 million in 2001, $4.7 million in 2000 and $5.3 million in 1999.

NONREGULATED GAS AND OIL RESERVES

In 2001, gas and oil reserves grew 62% after production to 1,184 Bcfe through a combined strategy of acquiring reserves and a successful drilling program. Market Resources achieved a 631% reserve replacement ratio in 2001 compared with 261% in 2000. QMR acquired 415 Bcfe of proved gas and oil reserves in the SEI acquisition. Reserve additions, revisions and purchases, and sales in place, amounted to 540 Bcfe in 2001. In January 2001, Market Resources completed the sale of 290 producing properties and a gas gathering system in the

Midcontinent. Daily production volumes of the properties sold approximated 4.3 MMcf of gas and 180 barrels of oil.

The five-year average finding cost was $.85 per Mcfe in 2001 compared with $.86 in 2000 and $.90 in 1999, excluding Wexpro.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
Net income	$101,134	$ 77,808	$ 43,888
Non-cash adjustments to net income	119,572	108,121	86,630
Changes in operating assets and liabilities	30,592	(54,680)	4,914
Net cash provided from operating activities	$251,298	$131,249	$135,432

Net cash provided from operating activities increased 91% in 2001 compared with 2000 as a result of 30% higher net income and collection of accounts receivable and the return of interest-bearing deposits with energy brokers. Timing differences in accounts receivable and deposits with energy brokers more than offset 77% increase in net income in 2000 compared with 1999.

Investing Activities

QMR acquired SEI for $403 million including debt and received 415 Bcfe of proved oil and gas reserves, gas processing capacity of 100 MMcf per day, 90 miles of gathering lines, 114,000 net acres of undeveloped leasehold acreage and four drilling rigs. In addition, QMR participated in drilling 337 wells (130 net wells) that resulted in 113 net gas wells, 10 net oil wells and 7 net dry holes. There were 56 gross wells in progress at year end. The success rate of completed net wells was 95%. QMR invested $7.7 million in the Rendezvous partnership that will provide gas gathering and compression services in southwestern Wyoming. The details of capital expenditures for 2001, 2000 and a forecast of 2002 are as follows:

Year Ended December 31,	2002 Forecast	2001	2000
	(In Thousands)		
Exploratory drilling	$ 500	$ 4,090	$ 446
Development drilling	142,600	188,091	97,361
Other exploration	2,100	1,433	342
Reserve acquisitions	100	370,068	65,130
Production	4,700	7,624	8,382
Gathering and processing	27,300	53,914	3,330
Storage		11,754	11,513
General	2,800	1,533	855
	$180,100	$638,507	$187,359

Financing Activities

Record capital spending and refinancing debt to take advantage of low interest rates combined to make 2001 a very active financing year. Net cash provided from operating activities of $251.3 million and proceeds from the sale of non-strategic assets of $32.7 million supplied 44% of the funding needed for capital expenditures. The remaining 56% was supplied through short- and long-term debt offerings. QMR borrowed $415 million, $280 million of which was in the form of a short-term bridge loan, to finance its acquisition of SEI. A portion of the bridge loan was subsequently refinanced with a one-year callable commercial paper note in the amount of $220 million. The commercial paper note was partially repaid with the proceeds of $200 million of five-year private placement notes with a 7% interest rate, issued January 16, 2002. The terms of the private placement notes required registration of the notes with the Securities and Exchange Commission. A registration statement was filed February 22, 2002 that became effective March 4, 2002. The exchange notes are expected to be issued in April 2002. In March 2001, QMR sold $150 million of 10-year notes with a 7.5% interest rate and used the proceeds to reduce debt.

In 2000, Market Resources initiated an unrated commercial-paper program with $100 million of capacity. Commercial-paper borrowings are limited to and supported by available capacity on Market Resources' existing revolving credit facility. Market Resources had a commercial-paper balance of $12.5 million at December 31, 2000 and no borrowing under this arrangement at December 31, 2001.

QMR reported negative working capital of $218.5 million at December 31, 2001. As a result of purchasing SEI, QMR borrowed $220 million on a short-term basis. Subsequently, the short-term loan was reduced by $100 million from an offering of long-term debt in January 2002. QMR plans to further reduce the balance in short-term debt through the sale of non-strategic assets and cash flows from operations.

QMR's consolidated capital structure consisted of 43% long-term debt and 57% common shareholder's equity at December 31, 2001. Considering short-term debt in the calculation increases the debt portion to 56%. The Company's long-term debt has been rated BBB+ by Standard and Poor's and Baa2 by Moody's.

Critical Accounting Policies

The Company's consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States. Management believes the following accounting policies may involve a higher degree of complexity and judgment.

SUCCESSFUL EFFORTS ACCOUNTING FOR GAS AND OIL OPERATIONS

Under the successful efforts method of accounting, the Company capitalizes the costs of acquiring leaseholds, drilling development wells and successful exploratory wells and purchasing related support equipment and facilities. The costs of unsuccessful exploratory wells are charged to expense when it is determined that such wells have not located proved reserves. Unproved leaseholds costs are periodically reviewed for impairment. Costs related to impaired prospects are charged to expense. Costs of geological and geophysical studies and other exploratory activities are expensed as incurred. Costs associated with production and general corporate activities are expensed in the period incurred. The Company recognizes gain or loss on the sale of properties on a field basis.

Capitalized proved leasehold costs are depleted on the unit-of-production method based on proved reserves on a field basis. All other capitalized costs associated with oil and gas properties are depreciated on the unit-of-production method based on proved developed reserves on a field basis. The Company engages independent consultants to calculate 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.

WEXPRO SETTLEMENT AGREEMENT

Wexpro's operations are subject to the terms of the Wexpro settlement agreement. The agreement was effective August 1, 1981, and sets forth the rights of Questar Gas' utility operations to share in the results of Wexpro's operations and the rate of return that Wexpro will earn for managing Questar Gas' reserves. The agreement was approved by the PSCU and PSCW in 1981 and affirmed by the Supreme Court of Utah in 1983.

ACCOUNTING FOR DERIVATIVES

On January 1, 2001, the Company adopted the accounting provisions of SFAS 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 addresses the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. Under the standard, the Company is required to carry all derivative instruments in the balance sheet at fair value. The accounting for changes in fair value, which result in gains or losses, of a derivative instrument depends on whether such instrument has been designated and qualifies as part of a hedging relationship and, if so, depends on the reason for holding it. The Company structured virtually all of its energy derivative instruments as cash flow hedges. Any changes in the fair value of cash flow hedges are recorded on the balance sheet until the underlying gas or oil is produced.

The cumulative effect of this accounting change decreased other comprehensive income by $79.4 million (after tax) and did not have a material effect on income at adoption. Of the cumulative effect recorded in other comprehensive income, $44.6 million (after tax) was reclassified into the Consolidated Income Statement during 2001.

REVENUE RECOGNITION

Revenues are recognized in the period that services are provided or products are delivered. The Company's exploration and production operations use the sales method of accounting for gas revenues, whereby revenue is recognized on all gas sold to purchasers. A liability is recorded to the extent that the Company has an imbalance in excess of its share of remaining reserves in an underlying property.

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

QMR's primary market-risk exposures arise from commodity-price changes for natural gas, oil and other hydrocarbons and changes in long-term interest rates. The Company has an investment in a foreign operation that may subject it to exchange-rate risk. A Market Resources subsidiary has long-term contracts for pipeline capacity for the next several years and is obligated to pay for transportation services with no guarantee that it will be able to recover the full cost of these transportation commitments.

HEDGING POLICY

The Company has established policies and procedures for managing commodity price risks through the use of commodity-based derivative arrangements. Primary objectives of these hedging transactions are to support the Company's earnings targets and to protect earnings from falling commodity prices. The Company will target between 50 and 75% of the current year's production to be hedged at or above budget levels by the end of March in the current year. The Company will ladder in these hedges, to reach forward beyond the current year when price levels are attractive. The volume of production hedged and the mix of derivative instruments employed are regularly evaluated and adjusted by management in response to changing market conditions and reviewed periodically by the Board of Directors. Additionally, under the terms of the Market Resources' revolving credit facility, not more than 75% of Market Resources' production quantities can be committed to hedge arrangements. The Company does not enter into derivative arrangements for speculative purposes.

ENERGY-PRICE RISK MANAGEMENT
Oil and natural gas prices fluctuate in response to changes in supply and demand. Market Resources bears a majority of the risk associated with commodity price changes and uses hedge arrangements in the normal course of business to limit the risk of adverse price movements. However, these same arrangements usually limit future gains from favorable price movements.

Market Resources held hedge contracts covering the price exposure for about 70.2 million dth of gas and 1.1 million bbl of oil at December 31, 2001. A year earlier the contracts covered 50.5 million dth of natural gas and 1 million bbl of oil. The hedging contracts exist for a significant share of equity gas and oil production and for a portion of gas-marketing transactions. The contracts at December 31, 2001, had terms extending through December 2003, with about 75% of those contracts expiring by the end of 2002.

The undiscounted mark-to-market adjustment of financial gas and oil price-hedging contracts at December 31, 2001 was a positive $37.7 million. A 10% decline in gas and oil prices would add $14.8 million to the mark-to-market calculation; while a 10% increase in prices would deduct $14.8 million. The mark-to-market adjustment of gas and oil price-hedging contracts at December 31, 2000 was a negative $98 million. A 10% decline in gas and oil prices at that time would decrease the mark-to-market adjustment by $18.1 million to $79.9 million. Conversely, a 10% increase in prices would have resulted in an $18.1 million negative mark-to-market adjustment to a negative $116.1 million balance at that date. The calculations reflect energy prices posted on the NYMEX, various "into the pipe" postings, and fixed prices on the indicated dates. These sensitivity calculations do not consider changes in the fair value of the corresponding scheduled physical transactions (i.e., the correlation between the index price and the price to be realized for the physical delivery of gas or oil production), which should largely offset the change in value of the hedge contracts. Also, the sensitivity measures exclude mark-to-market calculations on physical hedge contracts, where settlement is achieved through delivery of the gas or oil as opposed to cash settlements with a counterparty.

LIQUIDITY ACCELERATORS
QMR has entered into commodity price hedging contracts with several counterparties. The counterparties are banks and energy trading firms. In some contracts the amount of credit allowed before QMR must post collateral for out-of-the-money hedges varies depending on the credit rating of QMR's debt. In cases where this arrangement exists, if QMR's credit ratings fall below investment grade (BBB- by Standard & Poor's or Baa3 by Moody's) counterparty credit generally falls to zero.

INTEREST-RATE RISK MANAGEMENT
QMR held $150 million of fixed rate debt with a fair value of $147.8 million at December 31, 2001. The fair value of fixed rate debt is subject to change as interest rates fluctuate. The Company held floating-rate long-term debt at December 31, 2001 and 2000 amounting to $253.9 million and $244.4 million, respectively. The book value of variable-rate debt approximates fair value. If interest rates declined by 10%, the annual interest costs paid on variable-rate long-term debt would decrease about $.7 million based on the balance outstanding at December 31, 2001 and $1.7 million for the year earlier balance. Effective October 2001, the Company hedged $100 million of variable-rate debt by entering into a fixed-rate interest swap for one year. Due to declining interest rates at the end of 2001, the mark-to-market adjustment of the interest rate swap resulted in an unrealized loss of $627,000 and $67,000 of additional interest expense.

FOREIGN CURRENCY RISK MANAGEMENT
The Company does not hedge the foreign currency exposure of its foreign operation's net assets and long-term debt. Long-term debt held by the foreign operation amounting to $61.1 million (U.S.) is expected to be repaid from future operations of the foreign company.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may", "will", "could", "expect", "intend", "project", "estimate", "anticipate", "believe", "forecast", or "continue" or the negative thereof or variations thereon or similar terminology. Although these statements are made in good faith and are reasonable representations of the Company's expected performance at the time, actual results may vary from management's stated expectations and projections due to a variety of factors.

Important assumptions and other significant factors that could cause actual results to differ materially from those expressed or implied in forward-looking statements include changes in general economic conditions, gas and oil prices and supplies, competition, rate-regulatory issues, regulation of the Wexpro settlement agreement, availability of gas and oil properties for sale or for exploration and other factors beyond the control of the Company. These other factors include the rate of inflation, quoted prices of securities available for sale, the weather and other natural phenomena, the effect of accounting policies issued periodically by accounting standard-setting bodies, and adverse changes in the business or financial condition of the Company.

ITEM 8. STATEMENTS AND SUPPLEMENTARY DATA.

The Company's financial statements are included in Part IV, Item 14, herein.

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

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

PART III

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

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a)(1)(2) Financial Statements and Financial Statement Schedules. The financial statements and schedule identified in the List of Financial Statements are filed as part of this report.

(3) Exhibits. The following is a list of exhibits required to be filed as a part of this report in Item 14(c).

EXHIBIT NO.	DESCRIPTION
3.1.*	Articles of Incorporation dated April 27, 1988 for Utah Entrada Industries, Inc. (Exhibit No. 3.1. to the Company's Form 10 dated April 12, 2000.)
3.2.*	Articles of Merger, dated May 20, 1988, of Entrada Industries, Inc., a Delaware corporation and Utah Entrada Industries, Inc, a Utah corporation. (Exhibit No. 3.2. to the Company's Form 10 dated April 12, 2000.)
3.3.*	Articles of Amendment dated August 31, 1998, changing the name of Entrada Industries, Inc. to Questar Market Resources, Inc. (Exhibit No. 3.3. to the Company's Form 10 dated April 12, 2000.)
3.4.*	Bylaws (as amended effective February 8, 2000.) (Exhibit No. 3.4. to the Company's Form 10 dated April 12, 2000.)
4.1.*	Indenture dated as of March 1, 2001, between the Questar Market Resources, Inc. and Bank One, NA, as Trustee for the Company's 7 1/2% Notes due 2011. (Exhibit No. 4.01. to the Company's Current Report on Form 8-K dated March 6, 2001.)

4.2.*	Form of 7 1/2% Notes due 2011. (Exhibit No. 4.02. to the Company's Current Report on Form 8-K dated March 6, 2001.)
4.4.	U.S. Credit Agreement, dated April 19, 1999, by and among Questar Market Resources, Inc., as U.S. borrower, NationsBank, N.A., as U.S. agent, and certain financial institutions, as lenders, with the First Amendment dated May 17, 1999, the Second Amendment dated July 30, 1999, the

Third Amendment dated November 30, 1999, the Fourth Amendment dated April 17, 2000, the Fifth Amendment dated October 6, 2000, and the Sixth Amendment dated February 9, 2001. (Exhibit No. 4.1. to the Company's Form 10 dated April 12, 2000, for the U. S. Credit Agreement, and the First, Second and Third Amendments; Exhibit No. 4.1. to the Company's Form 10/A dated November 9, 2000, for the Fourth and Fifth Amendments. Exhibit No. 4.3. to the Company's Form 10-K Annual Report for 2000 for the Sixth Amendment.) The Seventh Amendment dated April 16, 2001, is filed as Exhibit 4.4 to this report.

4.5.	Long-term debt instruments with principal amounts not exceeding 10 percent of QMR's total consolidated assets are not filed as exhibits. The Company will furnish a copy of these agreements to the Commission upon request.
10.1.*	Stipulation and Agreement, dated October 14, 1981, executed by Mountain Fuel Supply Company [Questar Gas Company]; Wexpro Company; the Utah Department of Business Regulations, Division of Public Utilities; the Utah Committee of Consumer Services; and the staff of the Public Service Commission of Wyoming. (Exhibit No. 10(a) to Questar Gas Company's Form 10-K Annual Report for 1981.)
10.2.*	Stock Purchase Agreement among the Company, Shenandoah Energy and Shenandoah Energy's stockholders. (Exhibit No. 10.2. to the Company's Current Report on Form 8-K dated July 31, 2001.)
12.	Ratio of earnings to fixed charges.
21.	Subsidiary Information.
23.	Consent of Independent Auditors.
24.	Power of Attorney.

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

(b) The Company filed a Current Report on Form 8-K dated October 12, 2001 that contained the financial statements and pro forma information required as a result of the Company's acquisition of Shenandoah Energy, Inc.

ANNUAL REPORT ON FORM 10-K

ITEM 8, ITEM 14(a)(1) and (2), and (d)

LIST OF FINANCIAL STATEMENTS

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

YEAR ENDED DECEMBER 31, 2001

QUESTAR MARKET RESOURCES, INC.

SALT LAKE CITY, UTAH

FORM 10-K -- ITEM 14 (a) (1) AND (2)

QUESTAR MARKET RESOURCES, INC.

LIST OF FINANCIAL STATEMENTS AND

FINANCIAL STATEMENT SCHEDULES

The following financial statements of Questar Market Resources Inc. are included in Item 8:

Statements of income, Years ended December 31, 2001, 2000 and 1999

Balance sheets, December 31, 2001 and 2000

Statements of common shareholder's equity, Years ended December 31,2001, 2000 and 1999

Statements of cash flows, Years ended December 31, 2001, 2000 and 1999

Notes to financial statements

The following financial statement schedule is included in Item 8:

Schedule: Valuation and Qualifying Accounts

All other financial statement schedules, for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission, are not required under the related instructions or are inapplicable and therefore have been omitted.

Report of Independent Auditors

Board of Directors
Questar Market Resources, Inc.

We have audited the accompanying consolidated balance sheets of Questar Market Resources, Inc. as of December 31, 2001 and 2000, and the related consolidated statements of income, common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 14(a). These financial statements and statement are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial position of Questar Market Resources, Inc. at December 31, 2001 and 2000, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States. Also in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Notes 1 and 5 to the financial statements, effective January 1, 2001, Questar Market Resources, Inc. adopted Statement of Financial Accounting Standards No. 133, ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES.

/s/ Ernst & Young, LLP

Ernst & Young, LLP

Salt Lake City, Utah
February 8, 2002

QUESTAR MARKET RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
REVENUES			
From unaffiliated customers	$645,867	$649,200	$418,603
From affiliates	100,530	92,853	79,708
TOTAL REVENUES	746,397	742,053	498,311
OPERATING EXPENSES			
Cost of natural gas and other products sold	324,124	369,752	239,201
Operating and maintenance	112,087	106,761	79,719
Exploration	6,986	7,917	5,321
Depreciation, depletion and amortization	92,678	85,025	73,028
Abandonment and impairment of oil and gas properties	5,171	3,418	7,535
Production and other taxes	43,125	36,262	21,516
Wexpro settlement agreement - oil income sharing	2,885	4,758	2,292
TOTAL OPERATING EXPENSES	587,056	613,893	428,612
OPERATING INCOME	159,341	128,160	69,699
INTEREST AND OTHER INCOME	17,618	8,412	8,272
INCOME FROM UNCONSOLIDATED AFFILIATES	1,265	2,776	763
DEBT EXPENSE	(22,872)	(22,922)	(17,363)
INCOME BEFORE INCOME TAXES	155,352	116,426	61,371
INCOME TAXES	54,218		

38,618 17,483 ----------------------------------
-------------- NET INCOME $101,134 $77,808
$43,888
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See notes to consolidated financial statements.

QUESTAR MARKET RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS December 31, 2001 2000 ----------------------------- (In Thousands) CURRENT ASSETS Cash and cash equivalents $ 2,270 $ 3,980 Notes receivable from Questar Corporation 9,500 Accounts receivable, net of allowance of $2,849 in 2001 and $1,775 in 2000 76,935 126,030 Accounts receivable from affiliates 12,942 17,427 Federal income taxes recoverable 8,426 4,976 Hedging contracts 50,270 Qualifying hedging collateral 48,377 Inventories, at lower of average cost or market Gas and oil storage 14,245 7,618 Material and supplies 5,127 2,298 Prepaid expenses and other 11,661 4,828 ----------------------------- TOTAL CURRENT ASSETS 191,376 215,534 PROPERTY, PLANT AND EQUIPMENT Gas and oil properties - successful efforts accounting Proved properties 1,175,432 845,485 Unproved properties, not being amortized 176,141 55,608 Support equipment and facilities 11,414 13,179 Cost-of-service gas and oil operations - successful efforts accounting 405,783 348,403 Gathering, processing and marketing 210,394 137,484 --------------------------- - 1,979,164 1,400,159 Less allowances for depreciation, depletion and amortization Gas and oil properties 462,143 411,506 Cost-of-service gas and oil operations 207,410 193,029 Gathering, processing and marketing 61,777 58,388 --------------------------- 731,330 662,923 --------------------------- NET PROPERTY, PLANT AND EQUIPMENT 1,247,834 737,236 INVESTMENT IN UNCONSOLIDATED AFFILIATES 23,829 15,417 OTHER ASSETS Goodwill 66,823 Cash held in escrow account 5,387 Other 3,279 4,344 --------------------------- 70,102 9,731 --------------------------- $ 1,533,141 $ 977,918
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LIABILITIES AND SHAREHOLDER'S EQUITY

December 31, 2001 2000 ----------- ----------------------- (In Thousands) CURRENT LIABILITIES Short-term loans $ - $ 12,500 Notes payable to Questar 275,100 51,000 Accounts payable and accrued expenses Accounts and other payables 97,553 140,254 Accounts payable to affiliates 5,793 3,761 Production and other taxes 24,902 19,359 Interest 4,805 951 ---------------------------------- Total accounts payable and accrued expenses 133,053 164,325 Current portion of long-term debt 1,696 ---------------------------------- TOTAL CURRENT LIABILITIES 409,849 227,825 LONG-TERM DEBT, less current portion 402,226 244,377 DEFERRED INCOME TAXES 175,024 67,875 OTHER LIABILITIES 11,244 13,847 MINORITY INTEREST 8,369 5,483 COMMITMENTS AND CONTINGENCIES SHAREHOLDER'S EQUITY Common stock - par value $1 per share; authorized, 25,000,000 shares; issued and outstanding, 4,309,427 shares 4,309 4,309 Additional paid-in capital 116,027 116,027 Retained earnings 383,254 299,420 Cumulative other comprehensive income (loss) 22,839 (1,245) ---------------------------------- 526,429 418,511 ---------------------------------- $ 1,533,141 $ 977,918 ===================================

See notes to consolidated financial statements.

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

Cumulative Additional Other Compre- Common Paid-in Retained Comprehensive hensive Stock Capital Earnings Income (loss) Income -- (In Thousands) Balance at January 1, 1999 $4,309 $116,027 $209,719 $377 1999 net income 43,888 $43,888 Cash dividends (16,600) Dividend of shares of Questar Energy Services 1,905 Other comprehensive income: Unrealized loss on securities available for sale, net of income taxes of $1,557 (2,515) (2,515) Foreign currency translation adjustment, net of income taxes of $327 (605) (605) -- Balance at December 31, 1999 4,309 116,027 238,912 (2,743) $40,768 =========== 2000 net income 77,808 $77,808 Cash dividends (17,300) Other comprehensive income: Unrealized gain on securities available for sale, net of income taxes of $1,557 2,515 2,515 Foreign currency translation adjustment, net of income taxes of $949 (1,017) (1,017) -- Balance at December 31, 2000 4,309 116,027 299,420 (1,245) $79,306 =========== 2001 net income 101,134 $101,134 Cash dividends (17,300) Other comprehensive income: Cumulative effect of accounting change for energy hedges, net income taxes of $41,624 (79,376) (79,376) Unrealized gain on energy hedging transactions, net of income taxes of $57,048 105,295 105,295 Unrealized loss on interest rate swaps, net of income taxes of $235 (392) (392) Foreign currency translation adjustment, net of income taxes of $1,304 (1,443) (1,443) -- Balance at December 31, 2001 $4,309 $116,027 $383,254 $22,839 $125,218 ==

See notes to consolidated financial statements.

QUESTAR MARKET RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, 2001 2000 1999 -------- ------------------------------------- (In Thousands) OPERATING ACTIVITIES Net income $101,134 $77,808 $43,888 Adjustments to reconcile net income to net cash provided from operating activities Depreciation, depletion and amortization 94,776 85,733 75,570 Deferred income taxes 34,594 22,818 7,979 Abandonment and impairment of oil and gas properties 5,171 3,418 7,535 Income from unconsolidated affiliates, net of cash distributions (1,071) (2,117) (66) Gain from sale of properties and securities (13,898) (1,731) (4,388) Changes in operating assets and liabilities Accounts receivable and qualifying hedging collateral 113,072 (112,757) (2,631) Inventories (8,099) 1,337 (468) Hedging contracts (10,886) Prepaid expenses and other (4,012) (423) (83) Accounts payable and accrued expenses (53,800) 74,226 5,655 Federal income taxes (3,459) (11,207) 127 Other assets 1,031 (3,125) (783) Other liabilities (3,255) (2,731) 3,097 ------------- -------------------------------- NET CASH PROVIDED FROM OPERATING ACTIVITIES 251,298 131,249 135,432 INVESTING ACTIVITIES Capital expenditures Purchase of property, plant and equipment (630,807) (187,359) (103,384) Other investments (7,700) (24,864) ------------------ ----------------------------- (638,507) (187,359) (128,248) Proceeds from disposition of properties and equipment 32,729 2,254 37,888 Proceeds from sale of securities 18,424 1,214 - -- NET CASH USED IN INVESTING ACTIVITIES (605,778) (166,681) (89,146) FINANCING ACTIVITIES Change in notes receivable from Questar (9,500) 4,000 21,100 Change in notes payable to Questar 224,100 26,500 (97,300) Change in short-term debt (12,500) 12,500 Change in cash in escrow 5,387 31,340 (36,727) Checks written in excess of cash balances (1,246) 1,246 Issuance of long-term debt 405,000 61,725 275,000 Payment of long-term debt (242,837) (80,087) 195,000) Other financing 646 2,955 Payment of dividends (17,300) (17,300) (16,600) -------------------- -------------------------- NET CASH PROVIDED FROM (USED IN) FINANCING ACTIVITIES 352,996 40,387 (48,281) Foreign currency translation adjustments (226) (975) 101 ------------------- --------------------------- Change in cash and cash equivalents (1,710) 3,980 (1,894) Beginning cash and cash equivalents 3,980 1,894 -- ENDING CASH AND CASH EQUIVALENTS $2,270 $3,980 $ -
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See notes to consolidated financial statements.

QUESTAR MARKET RESOURCES, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Summary of Accounting Policies

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements contain the accounts of Questar Market Resources, Inc. and subsidiaries (the "Company" or "QMR" or "Market Resources"). The Company is a wholly owned subsidiary of Questar Corporation ("Questar"). QMR, through its subsidiaries, conducts gas and oil exploration, development and production, gas gathering and processing, and wholesale-energy marketing. Questar Exploration and Production ("Questar E & P") and Shenandoah Energy Inc. ("SEI"), conduct exploration, development and production activities. Wexpro Company ("Wexpro") operates and develops producing properties on behalf of Questar Gas. Questar Gas Management and SEI conduct gas gathering and plant processing activities. Questar Energy Trading performs wholesale energy marketing activities and through a 75% interest in Clear Creek Storage Company, LLC, operates a private gas-storage field. All significant intercompany balances and transactions have been eliminated in consolidation.

INVESTMENTS IN UNCONSOLIDATED AFFILIATES: QMR uses the equity method to account for investment in affiliates in which it does not have control. The principal affiliates are Canyon Creek Compression Co., Blacks Fork Gas Processing Co. and Rendezvous Gas Services LLC. Generally, QMR's investment in these affiliates equals the underlying equity in net assets.

USE OF ESTIMATES: The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent liabilities reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

REVENUE RECOGNITION: Revenues are recognized in the period that services are provided or products are delivered. QMR uses the sales method of accounting for gas revenues, whereby revenue is recognized on all gas sold to purchasers. A liability is recorded to the extent that the Company has sold gas in excess of its share of remaining reserves in an underlying property. The Company's net gas imbalances at December 31, 2001 and 2000 were not significant.

WEXPRO SETTLEMENT AGREEMENT - OIL INCOME SHARING: Wexpro settlement agreement-oil income sharing represents payments made to Questar Gas for its share of the income from oil and NGL products associated with cost-of- service oil properties pursuant to the terms of the Wexpro settlement agreement (Note 9).

REGULATION OF UNDERGROUND STORAGE: Clear Creek Storage Company, LLC operates an underground gas storage facility that is under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The FERC establishes rates for the storage of natural gas, and regulates the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment.

CASH AND CASH EQUIVALENTS: Cash equivalents consist principally of repurchase agreements with maturities of three months or less. In almost all cases, the repurchase agreements are highly liquid investments in overnight securities made through the Company's commercial bank accounts that result in available funds the next business day.

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

PROPERTY, PLANT AND EQUIPMENT: Property, plant and equipment is stated at cost. On July 1, 2001, QMR elected to change its accounting method for gas and oil properties from the full cost method to the successful efforts method. As a result, on December 11, 2001, the Company filed an amended Form 10-K for the year ended December 31, 2000 to retroactively restate financial statements to reflect this change in accounting method. Previously reported earnings decreased $7.2 million and $2.0 million for the years ended December 31, 2000 and 1999, respectively.

GAS AND OIL PROPERTIES

Under the successful efforts method of accounting, the Company capitalizes the costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, and purchasing related support equipment and facilities. The costs of unsuccessful exploratory wells are charged to expense when it is determined that such wells have not located proved reserves. Unproved leaseholds costs are periodically reviewed for impairment. Costs related to impaired prospects are charged to expense. Costs of geological and geophysical studies and other exploratory activities are expensed as incurred. Costs associated with production and general corporate activities are expensed in the period incurred. The Company recognizes gain or loss on the sale of properties on a field basis.

Capitalized proved leasehold costs are depleted on 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 on the unit-of-production method based on proved developed reserves on a field basis. Costs of future site restoration, dismantlement, and abandonment of producing properties are considered part of depreciation, depletion and amortization expense for tangible equipment by assuming no salvage value in the calculation of the unit-of-production rate.

COST-OF-SERVICE GAS AND OIL OPERATIONS

As ordered by the Public Service Commission of Utah ("PSCU"), the successful efforts method of accounting is utilized with respect to costs associated with certain "cost of service" gas and oil properties managed and developed by Wexpro and regulated for ratemaking purposes. Cost-of-service gas and oil properties are those properties for which the operations and return on investment are regulated by the Wexpro settlement agreement (see Note 9). In accordance with the settlement 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 settlement agreement, allowing Questar Gas to share in the proceeds for the purpose of reducing natural gas rates.

Capitalized costs are depreciated on an individual field basis using the unit-of-production method based upon proved developed gas and oil reserves attributable to the field. Costs of future site restoration, dismantlement, and abandonment for producing properties are considered as part of depreciation and amortization expense for tangible equipment by assuming no salvage value in the calculation of the unit-of-production rate.

GATHERING, PROCESSING AND MARKETING
The investments in gathering facilities, processing plants and other general support property, plant and equipment are generally depreciated using the straight-line method based upon estimated useful lives ranging from 3 to 20 years.

DEPRECIATION, DEPLETION AND AMORTIZATION

For the year ended December 31,	2001	2000	1999
	(In Thousands)		
Depreciation, depletion and amortization expense			
Gas and oil properties	$70,601	$65,169	$55,477
Cost-of-service oil and gas operations	15,051	13,922	12,665
Gathering, processing and marketing	7,026	5,934	4,886
	$92,678	$85,025	$73,028

Average depreciation, depletion and amortization rates per Mcf equivalent for the year ended December 31, were as follows:

	2001	2000	1999
Gas and oil properties			
U.S.	$0.79	$0.73	$0.72
Canada (in U.S. dollars)	1.10	1.12	0.63
Combined U.S. and Canada	0.83	0.78	0.71
Cost-of-service gas and oil operations	0.49	0.44	0.42

TEST FOR IMPAIRMENT OF LONG-LIVED ASSETS
Gas and oil properties are evaluated by field for potential impairment; other properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. An impairment is indicated when a triggering event occurs and the estimated undiscounted future net cash flows of an evaluated asset are less than its carrying value.

CAPITALIZED INTEREST AND ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION: When applicable, QMR capitalizes interest costs during the construction period of plant and equipment. However, the Company did not capitalize interest costs in 2001, 2000 or 1999. Under provisions of the Wexpro settlement agreement, the Company capitalizes an allowance for funds used during construction (AFUDC) on cost-of-service construction projects. The FERC requires the capitalization of AFUDC during the construction period of rate-regulated plant and equipment. AFUDC amounted to $.7 million, $2.2 million and $.4 million, in 2001, 2000 and 1999, respectively, and is included in Interest and Other Income in the Consolidated Statements of Income.

GOODWILL: QMR recorded $67 million of goodwill as the result of the acquisition of SEI completed July 31, 2001. The goodwill is not subject to amortization due to the change in accounting rules for goodwill. Refer to the "New Accounting Standards" discussion later in Note 1.

FOREIGN CURRENCY TRANSLATION: The Company conducts gas and oil exploration and production activities in western Canada. The local currency, the Canadian dollar, is the functional currency of the Company's foreign operations. Translation from Canadian dollars to U. S. dollars is performed for balance sheet accounts using the exchange rate in effect at the balance sheet date. Revenue and expense accounts are translated using an average exchange rate. Adjustments resulting from such translations are reported as a separate component of other comprehensive income in shareholders' equity. Deferred income taxes have been provided on translation adjustments because the earnings are not considered to be permanently invested.

ENERGY-PRICE FINANCIAL INSTRUMENTS: The Company has established policies and procedures for managing market risks through the use of commodity-based derivative arrangements. Primary objectives of these hedging transactions are to support the Company's earnings targets and to protect earnings from downward moves in commodity prices. It is expected that there will be a high degree of correlation between the changes in market value of hedging contracts and the market price ultimately received on the hedged physical transactions. The timing of production and the maturity of the hedge contracts are closely matched. Hedge prices are established in the areas of Market Resources' production operations. The Company settles most contracts in cash and recognizes the gains and losses on hedge transactions during the same time period as the related physical transactions. Cash flows from the hedge contracts are reported in the same category as cash flows from the hedged assets. Contracts that do not have high correlation with the related physical transactions are marked-to-market and with the adjustment recognized in the current-period income.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standard ("SFAS") 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." Refer to the "Energy-Price Risk Management" discussion in Note 5 - Financial Instruments and Risk Management. SFAS 133 addresses the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. Under the standard, the Company is required to carry all derivative instruments in the balance sheet at fair value. The accounting for changes in fair value, which result in gains or losses, of a derivative instrument depends on whether such instrument

has been designated and qualifies as part of a hedging relationship and, if so, depends on the reason for holding it. If certain conditions are met, the Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value, cash flows or foreign currencies. If the hedged exposure is a fair-value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting loss or gain 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 in the shareholder's equity section of the balance sheet and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in earnings immediately.

INTEREST-RATE FINANCIAL INSTRUMENTS: The Company utilizes interest-rate hedges to exchange fixed-rate interest payments for variable-rate interest payments. The difference between the fixed interest-rate payment made and the variable-rate payment is recorded as either an increase or decrease of interest expense.

CREDIT RISK: QMR's primary market areas are the Rocky Mountain regions of the United States and Canada and the Midcontinent region of the United States. Exposure to credit risk may be impacted by the concentration of customers in these regions due to changes in economic or other conditions. Customers include numerous industries that may be affected differently by 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. QMR monitors the creditworthiness of its counterparties, which generally are major financial institutions. Loss reserves are periodically reviewed for adequacy and may be established on a specific case basis.

INCOME TAXES: QMR accounts for income tax expense on a separate return basis. Pursuant to the Internal Revenue Code and associated regulations, QMR's operations are consolidated with those of Questar and its subsidiaries for income tax reporting purposes. The Company records tax benefits as they are generated. The Company receives payments from Questar for such tax benefits as they are utilized on the consolidated return.

COMPREHENSIVE INCOME: Comprehensive income is the sum of net income as reported in the Consolidated Statement of Income and other comprehensive income transactions reported in the Consolidated Statement of Statements of Shareholder's Equity. Other comprehensive income transactions reported by QMR result from changes in fair value of qualified energy derivatives, interest rate derivatives and securities available for sale, and changes in holding value resulting from foreign currency translation adjustments. These transactions are not the culmination of the earnings process, but result from periodically adjusting historical balances to market value. Income or loss is realized when the underlying products or securities available for sale are sold. Proceeds from selling available for sale securities were $18.4 million and $1.2 million for the year ended December 31, 2000 and 1999, respectively. Income tax expenses associated with realized gains from selling securities available for sale were $1.5 million in 2000 and $.1 million in 1999.

The balances of cumulative other comprehensive income (loss), net of income taxes at December 31, were as follows:

	2001	2000
	(In Thousands)	
Unrealized gain on energy hedging transactions	$25,919	
Unrealized loss on interest rate swap	(392)	
Foreign currency translation adjustment	(2,688)	($1,245)
Cumulative other comprehensive income (loss)	$22,839	($1,245)

BUSINESS SEGMENTS: QMR's line-of-business disclosures are presented based on the way senior management evaluates the performance of its business segments. Certain intersegment sales include intercompany profit.

NEW ACCOUNTING STANDARDS: In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 141, "Business Combinations," which addresses financial accounting and reporting for business combinations. SFAS 141 is effective for all business combinations initiated after June 30, 2001 and for all business combinations accounted for under the pooling method initiated before but completed after June 30, 2001. QMR applied the purchase method of accounting when recording an acquisition completed in the third quarter of 2001.

In June 2001, the FASB issued SFAS 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill shall be reviewed at least yearly for impairment or sooner if a specific trigger occurs. Goodwill acquired after July 1, 2001 is exempt from amortization. At December 31, 2001, QMR's balance of goodwill amounted to $67 million, all of which was acquired after July 1, 2001. QMR will adopt SFAS 142 as of January 1, 2002 and has up to six months to perform an initial goodwill impairment test. However, if impairment is indicated in the initial test, the impairment must be recorded retroactive to January 1, 2002 as a cumulative effect of a change in accounting method. Subsequent impairments will be charged to operating results. An initial test under the new accounting rules did not indicate an impairment of goodwill.

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations," which addresses, among other things, the financial accounting and reporting of the fair value of legal obligations associated with the retirement of tangible long-lived assets. The new standard requires that retirement costs be estimated at fair value, capitalized and depreciated over the life of the assets. The new standard may affect the cost basis of gas and oil and rate-regulated assets. SFAS 143 is effective for 2003. Market Resources has not evaluated the impact of SFAS 143.

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." The new standard addresses financial accounting and reporting for the impairment or disposal of long-lived assets, specifically, for a segment of a business accounted for as a discontinued operation and modifies the provisions of SFAS 121. SFAS 144 is effective for 2002. Market Resources has not evaluated the impact of SFAS 144.

Note 2 - Acquisitions

The Company acquired 100% of the common stock of SEI on July 31, 2001 for $403 million in cash including assumed debt. SEI was a privately held Denver-based exploration, production, gathering and drilling company. QMR obtained an estimated 415 billion cubic feet equivalent of proved oil and gas reserves, gas processing capacity of 100 MMcf per day, 90 miles of gathering lines, 114,000 acres of net undeveloped leasehold acreage and four drilling rigs. SEI operations are located primarily in the Uintah Basin of eastern Utah. The transaction was accounted for as a purchase business combination in accordance with accounting principles generally accepted in the United States. The purchase price in excess of the estimated fair value of the assets was assigned to goodwill. The acquisition was initially financed through bank borrowings.

Assets purchased and liabilities assumed were as follows:

	(In Thousands)
Current assets, net of cash acquired	$17,332
Property, plant and equipment	401,054
Goodwill	66,823
Other assets	124
Current liabilities	(24,328)
Other liabilities	(8,410)
Deferred income taxes	(54,364)
Other comprehensive loss	4,723
Purchase price, including acquisition costs	$402,954

The following unaudited pro forma consolidated results of operations assume the acquisition occurred on January 1, 2000. The pro forma financial information includes adjustments to:

- Depreciation expense to reflect the new basis of SEI's fixed assets.
- Interest expense to reflect financing costs of the acquisition.
- Operating expenses to reflect the resignation of several SEI executives.
- Exclude results of operations not purchased by QMR.
- Income tax expense based on pro forma income before income taxes.

	Year Ended December 31,	
	2001	2000
	(In Thousands)	
Revenues	$794,555	$785,872
Net income	98,552	68,240

On January 26, 2000, a subsidiary of QMR acquired 100% of the outstanding shares of Canor Energy Ltd from NI Canada ULC, a subsidiary of Northwest Natural Gas Co. for cash of $61 million (US) plus the assumption of $5.4 million of short-term debt. The transaction was accounted for as a purchase. Canor owns an interest in more than 800 wells located in Alberta, British Columbia and Saskatchewan provinces of Canada. Canor's proven gas and oil reserves were estimated at the time of purchase at 61.1 billion cubic feet equivalent.

Note 3 - Investment in Unconsolidated Affiliates

QMR, indirectly through subsidiaries, has interests in partnerships accounted for on an equity basis. These entities are engaged primarily in gathering or processing natural gas. As of December 31, 2001, these affiliates did not have debt obligations with third-party lenders. The principal partnerships and percentage ownership were as follows: Canyon Creek Compression Co. (15%), Blacks Fork Gas Processing Co. (50%) and Rendezvous Gas Services LLC (50%).

Summarized results of the partnerships are listed below.

	2001	2000	1999
	(In Thousands)		
YEAR ENDED DECEMBER 31,			
Revenues	$24,992	$27,574	$19,096
Operating income	2,830	5,811	2,922
Income before income taxes	3,105	6,184	2,803
AT DECEMBER 31,			
Current assets	$21,000	$14,232	
Noncurrent assets	38,862	26,941	
Current liabilities	3,893	3,940	
Noncurrent liabilities	2,529	946	

Note 4 - Debt

QMR has a $280 million revolving credit facility and $150 million of 7.5% notes. The revolving credit facility is segmented into United States and Canadian portions of $221.7 million and $58.3 million, respectively. The interest rate is generally equal to LIBOR plus a premium. QMR's revolving credit facility contains covenants specifying a minimum amount of net equity and a maximum ratio of debt to equity. Under the most restrictive terms of the revolving credit facility, Market Resources could pay a dividend of $47.8 million.

December 31,	2001	2000
	(In Thousands)	
SHORT-TERM DEBT		
Commercial paper		$ 12,500
Notes payable to Questar	$275,100	$ 51,000
(Interest rate at December 31, 2001 and 2000, 2.31% and 6.91%, respectively)		
	$275,100	$ 63,500
LONG-TERM DEBT		
Revolving-credit loan due 2002 - 2007 with variable interest rates (2.85% at December 31, 2001)	$253,922	$244,377
7.5% Notes due 2011	150,000	
	403,922	244,377
Less current portion	1,696	
	$402,226	$244,377

Maturities of long-term debt for the five years following December 31, 2001, in thousands of dollars are as follows:

2002	$ 1,696
2003	1,696
2004	221,696
2005	1,696
2006	1,696

To purchase SEI, QMR borrowed $415 million of which $280 million was in the form of a short-term bridge loan. The bridge loan was subsequently refinanced with borrowings from banks and a one-year callable commercial paper note in the amount of $220 million. The commercial paper note and bank borrowings were reduced with the proceeds of a five-year, $200 million private placement note with a 7% interest rate issued January 16, 2002. The terms of the private

placement note required that the notes be registered with the SEC. A registration statement was filed February 22, 2002 that became effective March 4, 2002. The exchange notes are expected to be issued in April 2002. In March 2001, QMR sold $150 million of 10-year notes with a 7.5% interest rate and used the proceeds to reduce bank debt.

Questar makes loans to QMR under a short-term borrowing arrangement and earns interest based on a rate that adjusts monthly. The interest rate is identical to the interest rate charged by the Company for loans to Questar.

Cash paid for interest was $22.9 million in 2001, $23.4 million in 2000 and $17 million in 1999.

Note 5 - Financial Instruments and Risk Management

The carrying amounts and estimated fair values of the Company's financial instruments were as follows:

	December 31, 2001		December 31, 2000	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
(In Thousands)				
Financial assets				
Cash and cash equivalents	$ 2,270	$ 2,270	$ 3,980	$ 3,980
Notes receivable	9,500	9,500		
Financial liabilities				
Short-term loans	275,100	275,100	63,500	63,500

Long-term
debt
402,226
401,590
244,377
244,377
Energy-
price
hedging
contracts
50,897
50,897 -
(98,000)
Interest-
rate swap
(627)
(627)

Market Resources used the following methods and assumptions in estimating fair values:

CASH AND CASH EQUIVALENTS, NOTES RECEIVABLE AND SHORT-TERM LOANS - 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 QMR's current borrowing rates;
ENERGY-PRICE HEDGING CONTRACTS - fair value of the contracts is based on market prices as posted on the NYMEX from the last trading day of the year. The average price of the oil contracts at December 31, 2001, was $25.47 per barrel and was based on the average of fixed amounts in contracts which settle against the NYMEX. All oil contracts relate to equity production where basis adjustments would result in a net-to-the-well price of $24.45 per barrel. The average price of the gas contracts at December 31, 2001 was $3.77 per MMBtu representing the average of contracts with different terms including fixed, various "into the pipe" postings and NYMEX references. Energy-price hedging contracts were in place for equity gas production and gas-marketing transactions. Deducting transportation and heat-value adjustments on the hedges of equity gas as of December 31, 2001, would result in a price between $3.43 and $3.57 per Mcf, net-back-to-the-well.
INTEREST-RATE SWAP - the mark-to-market valuation equals a discounted present value of future cash flow using current market rates.

Fair value is calculated at a point in time and does not represent the amount QMR would pay to retire the debt securities. In the case of energy-price hedges, the fair value calculation does not consider the fair value of the corresponding scheduled physical transactions (i.e., the correlation between the index price and the price to be realized for the physical delivery of gas or oil production).

ENERGY-PRICE RISK MANAGEMENT
Market Resources held financial energy-price hedge contracts covering the exposure for about 70.2 million dth of gas and 1.1 million barrels of oil at December 31, 2001. A year earlier the contracts covered 50.5 million dth of

natural gas and 1.0 million barrels of oil. Hedging contracts exist for a significant share of Questar-owned gas and oil production and for a portion of gas-marketing transactions. The contracts at December 31, 2001, had terms extending through December 2003. About 75% of those contracts, representing $27.0 million, settle and will be reclassified from other comprehensive income in the next 12 months.

On January 1, 2001, the Company adopted the accounting provisions of SFAS 133 and recorded a cumulative effect of this accounting change that decreased other comprehensive income by $79.4 million (after-tax). The Company structured a majority of its energy-price derivative instruments as cash flow hedges and as a result of adopting SFAS 133 recorded a $121 million hedging liability for derivative instruments. By the end of 2001, the Company's hedging contracts were on a net basis, in-the-money. The results of hedging activities amounted to a $50.9 million current asset. Settlement of contracts in 2001 had resulted in the reclassification into income of $68 million ($44.6 million after-tax). The remaining change of $103.9 million resulted from a decrease in prices of gas and oil on futures markets. The offset to the hedging asset, net of income taxes, was a $25.9 million unrealized gain on hedging activities recorded in other comprehensive income in the shareholder's equity section of the balance sheet. The ineffective portion of hedging transactions recognized in earnings was not significant. The fair-value calculation does not consider changes in fair value of the corresponding scheduled equity physical transactions.

INTEREST-RATE RISK MANAGEMENT
Effective October 2001, QMR hedged $100 million of variable-rate debt by entering into a fixed-rate interest swap for one year. Due to declining interest rates at the end of 2001, the mark-to-market adjustment of the interest rate

swap resulted in an unrealized loss of $627,000 and $67,000 of additional interest expense.

CREDIT RISK MANAGEMENT

Management increased its bad debt reserves as it monitored the effect on collections resulting from significantly higher energy prices in the first half of 2001, an economic recession and an increase in bankruptcies filed in the United States.

FOREIGN CURRENCY RISK MANAGEMENT

The Company does not hedge the foreign currency exposure of its foreign operation's net assets and long-term debt. Long-term debt held by the foreign operation, amounting to $61.1 million (U.S.), is expected to be repaid from future operations of the foreign company.

Note 6 - Income Taxes

The components of income taxes for years ended December 31 were as follows:

	2001	2000	1999
	(In Thousands)		
Federal			
Current	$19,962	$13,678	$11,411
Deferred	24,528	19,947	4,430
State			
Current	1,022	1,129	1,568
Deferred	2,837	1,763	959
Foreign	5,869	2,101	(885)
	$54,218	$38,618	$17,483

The difference between the statutory federal income tax rate and QMR's effective income tax rate is explained as follows:

	2001	2000	1999
	(In Percentages)		
Statutory federal income tax rate	35.0	35.0	35.0
Increase (decrease) as a result of:			
State income tax rate, net of federal income tax credit	1.6	1.6	2.7
Non-conventional fuel credits	(3.3)	(4.0)	(8.6)
Foreign income taxes	1.7	0.6	(0.3)
Other	(0.1)		(0.3)
Effective income tax rate	34.9	33.2	28.5

Significant components of the Company's deferred income taxes at December 31 were as follows:

	2001	2000
	(In Thousands)	
Deferred tax liabilities		
Property, plant and equipment	$187,546	$77,737
Other	746	775
Total deferred tax liabilities	188,292	78,512
Deferred tax assets		
Ad valorem taxes	5,106	3,277
Reserves, compensation plans and other	8,162	7,360
	13,268	10,637
Net deferred income taxes	$175,024	$67,875

Cash paid for income taxes amounted to $22.3 million in 2001, $25.6 million in 2000 and $7.2 million in 1999.

Note 7 - Litigation and Commitments

LEGAL PROCEEDINGS

There are various legal proceedings against Market Resources. While it is not currently possible to predict or determine the outcomes of these proceedings, it is the opinion of management that the outcomes will not have a materially adverse effect on the Company's results of operations, financial position or liquidity.

COMMITMENTS

Questar Energy Trading has contracted for firm-transportation services with various pipelines through 2016. Due to market conditions and competition, it is possible that Questar Energy Trading may not be able to recover the full cost of these transportation commitments. Annual payments and the years covered are as follows:

	(In Thousands)
2002	$3,351
2003	2,489
2004	1,681
Yearly commitment fee 2005 through 2016	194

QMR rents office space throughout its scope of operations from third-party lessors and leases space in an office building located in Salt Lake City, Utah from an affiliated company. The minimum future payments under the terms of long-term operating leases for the Company's primary office locations for the five years following December 31, 2001, are as follows:

	(In Thousands)
2002	$2,051
2003	1,022
2004	536
2005	262
2006	93

Total minimum future rental payments have not been reduced for sublease rental receipts of $58,000 which are expected to be received in the year ended December 31, 2002. Total rental expense amounted to $2,223,000 in 2001, $2,087,000 in 2000 and $1,804,000 in 1999. Sublease rental receipts were $294,000 in 2001, $118,000 in 2000 and $94,000 in 1999.

Note 8 - Employment Benefits

Pension Plan: Substantially all of QMR's employees are covered by Questar's defined benefit pension plan, although some employees have elected other benefits in place of a pension benefit. Benefits are generally based on the employee's age at retirement, years of service and highest earnings in a consecutive 72-pay period interval during the ten years preceding retirement. The Company's policy is to make contributions to the plan at least sufficient to meet the minimum funding requirements of applicable laws and regulations. Plan assets consist principally of equity securities and corporate and U.S. government debt obligations. Pension cost was $1.0 million in 2001, $.4 million in 2000 and $.9 million in 1999.

QMR's portion of plan assets and benefit obligations is not determinable because the plan assets are not segregated to meet QMR's pension obligations. If the Company were to withdraw from the pension plan, the pension obligation for QMR's employees would be retained by the pension plan. At December 31, 2001, Questar's accumulated benefit obligation exceeded the fair value of plan assets.

Postretirement Benefits Other Than Pensions: Market Resources pays a portion of health-care costs and life insurance costs for employees. The Company links the health-care benefits to years of service and limits the Company's monthly health-care contribution per individual to 170% of the 1992 contribution. Employees hired after December 31, 1996 do not qualify for postretirement medical benefits under this plan. Questar's policy is to fund amounts allowable for tax deduction under the Internal Revenue Code. Plan assets consist of equity securities, corporate debt obligations and U.S. government debt obligations. The Company is amortizing a transition obligation over a 20-year period beginning in 1992. Costs of postretirement benefits other than pensions were $1.3 million in 2001, $1.7 million in 2000 and $1.2 million in 1999.

Market Resources' portion of plan assets and benefit obligations related to postretirement medical and life insurance benefits is not determinable because the plan assets are not segregated to meet the Company's obligations. At December 31, 2001, Questar's accumulated benefit obligation exceeded the fair value of plan assets.

Postemployment Benefits: Market Resources 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 the present value of current and future costs. QMR's postemployment benefit liability at December 31, 2001 and 2000 was $.5 million and $.6 million, respectively based on a discount rate of 7.75%.

Employee Investment Plan: Market Resources participates in Questar's Employee Investment Plan (EIP), which allows eligible employees to purchase Questar common stock or other investments through payroll deduction of pretax earnings. QMR pays for contributions of Questar common stock to the EIP of approximately 80% of the employees' purchases up to 6% of eligible earnings and contributes an additional $200 of common stock in the name of each eligible employee. The Company's expense to the plan was $1.3 million in 2001, $1.1 million in 2000 and $.9 million in 1999.

Note 9 - Related Party Transactions

QMR receives a significant portion of its revenues from services provided to Questar Gas Company. The Company received $100.5 million in 2001, $92.5 million in 2000 and $79.3 million in 1999 for operating cost-of-service gas properties, gathering gas and supplying a portion of gas for resale, among other services provided to Questar Gas. Operation of cost-of-service gas properties is described in Wexpro Settlement Agreement (Note 10). QMR also received revenues from other affiliated companies totaling $.4 million in both 2000 and 1999. In 2001, revenues from Questar Gas accounted for all of QMR's intercompany transactions.

Questar performs certain administrative functions for QMR and charged QMR $7.8 million in 2001, $6.6 million in 2000 and $4.5 million in 1999. QMR includes these costs in operating and maintenance expenses. Questar allocates the costs based on each affiliate proportional share of revenues, net of gas costs; property, plant and equipment; and payroll. Management believes that the allocation method is reasonable.

QMR's subsidiaries contracted for transportation and storage services with Questar Pipeline and paid $1.3 million in 2001, $2.1 million in 2000 and $3.4 million in 1999 for these services.

Questar InfoComm Inc is an affiliated company that provides some information technology and communication services to Questar and its affiliated companies. QMR paid Questar InfoComm $1.4 million in 2001, $1.9 million in 2000 and $2.3 million in 1999.

QMR has a 5-year lease with Questar for space in an office building located in Salt Lake City, Utah. The building is owned by a third party. The third party has a lease arrangement with Questar Corp, which in turn sublets office space to affiliated companies. The lease between QMR and Questar expires October 2002. QMR has a five-year extension option. The lease payment for 2002 is $.7 million.

The Company received interest income from affiliated companies of $.6 million in 2001 and 2000 and $.7 million in 1999. Market Resources incurred debt expense to affiliated companies of $3.1 million in 2001, $2.5 million in 2000, $3.4 million in 1999.

Note 10 - Wexpro Settlement Agreement

Wexpro's operations are subject to the terms of the Wexpro settlement 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 settlement 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 13.6%. 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 18.6%. 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 developmental gas 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 21.6%.

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 13.6%.

Note 11 - Business Segment Information

QMR is a sub-holding company that has three primary business segments: exploration and production, the management and development of cost of service properties, and gathering, processing and marketing. QMR's reportable segments are strategic business units with similar operations and management objectives. The reportable segments are managed separately because each segment requires different operational assets, technology and management strategies.

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
Revenues from Unaffiliated Customers			
Exploration and production	$280,576	$245,728	162,475
Cost of service	12,465	15,179	8,844
Gathering, processing and marketing	352,826	388,293	247,284
	645,867	649,200	418,603
Revenues from Affiliated Companies			
Exploration and production	807	18	
Cost of service	88,936	73,721	62,335
Gathering, processing and marketing	10,787	19,114	17,373
	100,530	92,853	79,708
Depreciation, Depletion and Amortization Expense			
Exploration and production	70,601	65,169	55,477
Cost of service	15,051	13,922	12,665
Gathering, processing and marketing	7,026	5,934	4,886
	92,678	85,025	73,028
Operating Income			
Exploration and production	101,531	77,919	30,327
Cost of service	45,030	38,502	32,948
Gathering, processing and marketing	12,780	11,739	6,424
	$159,341	$128,160	$ 69,699

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
Interest and Other Income			
Exploration and production	$ 14,265	$ 387	$ 6,209
Cost of service	847	472	534
Gathering, processing and marketing	2,506	7,553	1,529
	17,618	8,412	8,272
Debt Expense			
Exploration and production	18,202	17,976	14,770
Cost of service	1,789	721	582
Gathering, processing and marketing	2,881	4,225	2,011
	22,872	22,922	17,363
Income Taxes			
Exploration and production	33,355	18,483	2,936
Cost of service	15,847	13,873	12,020
Gathering, processing and marketing	5,016	6,262	2,527
	54,218	38,618	17,483
Net income			
Exploration and production	64,452	42,137	18,830
Cost of service	28,241	24,380	20,880
Gathering, processing and marketing	8,441	11,291	4,178
	101,134	77,808	43,888
Fixed Assets - Net			
Exploration and production	900,844	502,766	428,780
Cost of service	198,373	155,374	137,584
Gathering, processing and marketing	148,617	79,096	71,354

1,247,834 737,236 637,718
===
Capital Expenditures Exploration and
production 549,096 140,487 75,842 Cost of
service 58,453 32,048 21,076 Gathering,
processing and marketing 30,958 14,824 31,330

- 638,507 187,359 128,248
===
GEOGRAPHIC INFORMATION Revenues United States
707,902 703,981 485,995 Canada 38,495 38,072
12,316 -------------------------------------
-------- 746,397 742,053 498,311
===
Fixed Assets - Net United States 1,171,697
648,089 611,075 Canada 76,137 89,147 26,643 --

$1,247,834 $737,236 $637,718
===

Note 11 - Supplemental Oil and Gas Information (Unaudited)

The Company uses the successful efforts accounting method for its gas and oil exploration and development activities. As ordered by the Public Service Commission of Utah, the successful efforts method of accounting is utilized with respect to costs associated with certain cost-of-service gas and oil properties managed and developed by Wexpro and regulated for ratemaking purposes. Cost-of-service gas and oil properties are those properties for which the operations and return on investment are regulated by the Wexpro settlement agreement (See Note 10).

Gas and Oil Exploration and Development Activities: The following information is provided with respect to Questar's gas and oil exploration and development activities, located in the United States and Canada.

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 follow:

- United States Canada Total ---------------
------------------------------ AS OF
DECEMBER 31, (In Thousands) 2001 Proved
properties $1,051,875 $123,557 $1,175,432
Unproved properties 165,066 11,075 176,141
Support equipment and facilities 11,017 397
11,414 -------------------------------------
-------- 1,227,958 135,029 1,362,987
Accumulated depreciation, depletion and
amortization 403,251 58,892 462,143 --------
------------------------------------ $
824,707 $ 76,137 $ 900,844
===
2000 Proved properties $ 732,078 $113,407 $
845,485 Unproved properties 30,940 24,668
55,608 Support equipment and facilities
12,002 1,177 13,179 ------------------------
--------------------- 775,020 139,252
914,272 Accumulated depreciation, depletion
and amortization 361,401 50,105 411,506 ----
-- $
413,619 $ 89,147 $ 502,766
===
1999 Proved properties $ 663,051 $ 54,096 $
717,147 Unproved properties 41,654 9,970
51,624 Support equipment and facilities
12,418 990 13,408 --------------------------
------------------- 717,123 65,056 782,179
Accumulated depreciation, depletion and
amortization 314,986 38,413 353,399 --------
------------------------------------ $
402,137 $ 26,643 $ 428,780
===

COSTS INCURRED

The following costs were incurred in gas and oil exploration and development activities:

YEAR ENDED DECEMBER 31, (In Thousands)	United States	Canada	Total
2001			
Property acquisition			
Unproved	$ 1,309	$ 318	$ 1,627
Proved	303,757		303,757
Exploration	14,063	1,755	15,818
Development	130,638	5,256	135,894
	$449,767	$ 7,329	$457,096
2000			
Property acquisition			
Unproved	$ 3,054	$14,703	$ 17,757
Proved	1,202	31,058	32,260
Exploration	6,433	3,664	10,097
Development	64,582	29,478	94,060
	$ 75,271	$78,903	$154,174
1999			
Property acquisition			
Unproved	$ 12,565	$ 337	$ 12,902
Proved	2,367	17	2,384
Exploration	8,402	323	8,725
Development	53,347	3,608	56,955
	$ 76,681	$ 4,285	$ 80,966

RESULTS OF OPERATIONS

Following are the results of operations of Market Resources' gas and oil exploration and development activities, before corporate overhead and interest expenses.

YEAR ENDED DECEMBER 31, 2001 (In Thousands)	United States	Canada	Total
Revenues			
From unaffiliated customers	$242,081	$38,495	$280,576
From affiliates	807		807
Total revenues	242,888	38,495	281,383
Production expenses	62,646	8,106	70,752
Exploration	5,236	1,785	7,021
Depreciation, depletion and amortization	58,537	12,064	70,601
Abandonment and impairment of gas and oil properties	3,571	1,600	5,171
Total expenses	129,990	23,555	153,545
Revenues less expenses	112,898	14,940	127,838
Income taxes - Note A	37,348	9,323	46,671
Results of operations before corporate overhead and interest expenses	$ 75,550	$ 5,617	$ 81,167

YEAR ENDED DECEMBER 31, 2000 (In Thousands)	United States	Canada	Total
Revenues			
From unaffiliated customers	$ 207,656	$38,072	$245,728
From affiliates	18		18
Total revenues	207,674	38,072	245,746
Production expenses	49,056	8,809	57,865
Exploration	5,533	2,442	7,975
Depreciation, depletion and amortization	51,973	13,196	65,169
Abandonment and impairment of gas and oil properties	2,327	1,091	3,418
Total expenses	108,889	25,538	134,427
Revenues less expenses	98,785	12,534	111,319
Income taxes - Note A	31,994	5,841	37,835
Results of operations before			

corporate overhead and interest expenses $
66,791 $ 6,693 $ 73,484
==
Year Ended December 31, 1999 Revenues $
150,159 $12,316 $162,475 ------------------
-------------------------- Production
expenses 41,856 3,681 45,537 Exploration
4,803 321 5,124 Depreciation, depletion and
amortization 51,927 3,550 55,477
Abandonment and impairment of gas and oil
properties 5,542 1,993 7,535 --------------
------------------------------ Total
expenses 104,128 9,545 113,673 ------------
------------------------------- Revenues
less expenses 46,031 2,771 48,802 Income
taxes - Note A 12,348 1,233 13,581 --------

Results of operations before corporate
overhead and interest expenses $ 33,683 $
1,538 $ 35,221
==

Note A - Income tax expenses have been reduced by non-conventional fuel tax credits of $5 million in 2001, $4.7 million in 2000 and $5.3 million in 1999.

ESTIMATED QUANTITIES OF PROVED GAS AND OIL RESERVES

Estimates of the reserves located in the United States were made by Ryder Scott Company, H. J. Gruy and Associates, Inc., Netherland, Sewell & Associates, and Malkewicz Hueni Associates, Inc., independent reservoir engineers. Estimated Canadian reserves were prepared by Gilbert Laustsen Jung Associates Ltd. and Sproule Associates Ltd. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development-drilling information becomes available. The quantities reported below are based on existing economic and operating conditions at December 31. All gas and oil reserves reported were located in the United States and Canada. The Company does not have any long-term supply contracts with foreign governments or reserves of equity investees.

Natural Gas Oil United States Canada Total United States Canada Total ---------------------
-- (MMcf) (MBbls)
PROVED RESERVES Balance at January 1, 1999 466,688 21,935 488,623 11,649 2,601 14,250
Revisions of estimates 4,155 (106) 4,049 4,031 372 4,403 Extensions and discoveries 77,737
1,720 79,457 794 257 1,051 Purchase of reserves in place 17,020 17,020 130 130 Sale of
reserves in place (11,984) (11,984) (3,665) (3,665) Production (59,839) (2,873) (62,712)
(1,876) (435) (2,311) ---
----------------------- Balance at December 31, 1999 493,777 20,676 514,453 11,063 2,795
13,858 Revisions of estimates 25,662 (7,890) 17,772 221 (64) 157 Extensions and discoveries
123,155 2,511 125,666 1,532 208 1,740 Purchase of reserves in place 846 52,000 52,846 1
1,520 1,521 Sale of reserves in place (1,885) (1,885) (17) (17) Production (61,722) (7,241)
(68,963) (1,484) (741) (2,225) --
------------------------------- Balance at December 31, 2000 579,833 60,056 639,889 11,316
3,718 15,034 Revisions of estimates (36,528) 1,341 (35,187) (1,950) (21) (1,971) Extensions
and discoveries 175,423 7,144 182,567 1,515 340 1,855 Purchase of reserves in place 300,353
300,353 19,185 19,185 Sale of reserves in place (19,072) (19,072) (531) (531) Production
(63,862) (6,712) (70,574) (1,797) (703) (2,500) --
--- Balance at December 31, 2001 936,147
61,829 997,976 27,738 3,334 31,072
==
PROVED-DEVELOPED RESERVES Balance at January 1, 1999 411,826 17,835 429,661 10,443 2,281
12,724 Balance at December 31, 1999 412,008 17,076 429,084 9,897 2,565 12,462 Balance at
December 31, 2000 434,122 55,623 489,745 9,696 3,077 12,773 Balance at December 31, 2001
534,761 53,036 587,797 19,417 2,566 21,983

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. 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 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.

YEAR ENDED DECEMBER 31,	United States	Canada	Total
(In Thousands)			
2001			
Future cash inflows	$ 2,541,716	$ 192,762	$ 2,734,478
Future production costs	(798,431)	(58,643)	(857,074)
Future development costs	(266,097)	(3,421)	(269,518)
Future income tax expenses	(392,152)	(38,767)	(430,919)
Future net cash flows	1,085,036	91,931	1,176,967
10% annual discount to reflect timing of net cash flows	(536,876)	(35,789)	(572,665)
Standardized measure of discounted future net cash flows	$ 548,160	$ 56,142	$ 604,302
2000			
Future cash inflows	$5,412,945	$568,771	$5,981,716
Future production costs	(955,827)	(73,583)	(1,029,410)
Future development costs	(107,355)	(2,900)	(110,255)
Future income tax expenses	(1,489,267)	(182,537)	(1,671,804)
Future net cash flows	2,860,496	309,751	3,170,247
10% annual discount to reflect timing of net cash flows	(1,316,114)	(136,445)	(1,452,559)
Standardized measure of discounted future net cash flows	$1,544,382	$173,306	$1,717,688
1999			
Future cash inflows	$ 1,332,761	$ 108,990	$ 1,441,751
Future production costs	(398,591)	(28,280)	(426,871)
Future development costs	(61,034)	(3,146)	(64,180)
Future income tax expenses	(188,988)	(10,353)	(199,341)
Future net cash flows	684,148	67,211	751,359
10% annual discount to reflect timing of net cash flows	(280,911)	(23,652)	(304,563)
Standardized measure of discounted future net cash flows	$ 403,237	$ 43,559	$ 446,796

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

Year Ended December 31,	2001	2000	1999
(In Thousands)			
Beginning balance	$1,717,688	$ 446,796	$348,376
Sales of oil and gas produced, net of production costs	(210,631)	(187,881)	(116,938)
Net changes in prices and production costs	(1,978,853)	1,638,170	171,392
Extensions and discoveries, less related costs	133,866	492,398	79,511
Revisions of quantity estimates	(31,451)	70,155	28,665
Purchase of reserves in place	303,757	32,260	2,384
Sale of reserves in place	(41,225)	(1,867)	(33,043)
Change in future development	(70,979)	(17,770)	(9,332)
Accretion of discount	171,769	44,680	34,837
Net change in income taxes	775,013	(776,276)	(61,807)
Change in production rate	(125,725)	(50,077)	(8,859)
Other	(38,927)	27,100	11,610
Net change	1,113,386)	1,270,892	98,420
Ending balance	$ 604,302	$1,717,688	$ 446,796

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 settlement 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 settlement agreement.

CAPITALIZED COSTS

Capitalized costs for cost-of-service gas and oil properties net of the related accumulated depreciation and amortization were as follows:

December 31,	2001	2000	1999
	(In Thousands)		
Proved properties	$405,783	$348,403	$318,451
Accumulated depreciation and amortization	207,410	193,029	180,867
	$198,373	$155,374	$137,584

COSTS INCURRED

Costs incurred by Wexpro for cost-of-service gas and oil producing activities were $58.5 million in 2001, $32.1 million in 2000 and $21.3 million in 1999.

RESULTS OF OPERATIONS

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

Year Ended December 31,	2001	2000	1999
	(In Thousands)		
Revenues			
From unaffiliated companies	$12,465	$15,179	$ 8,844
From affiliates - Note A	88,936	73,721	62,335
Total revenues	101,401	88,900	71,179
Production expenses	33,016	27,861	18,548
Depreciation and amortization	15,051	13,922	12,665
Total expenses	48,067	41,783	31,213
Revenues less expenses	53,334	47,117	39,966
Income taxes	19,181	16,923	14,602
Results of operations before corporate overhead and interest expenses	$34,153	$30,194	$25,364

Note A - Represents revenues received from Questar Gas pursuant to Wexpro Settlement Agreement.

ESTIMATED QUANTITIES OF PROVED GAS AND OIL RESERVES

The following estimates were made by the Company's reservoir engineers. Generally, no estimates are available for cost-of-service proved undeveloped reserves that may exist.

	Natural Gas	Oil
	(MMcf)	(MBbls)
PROVED DEVELOPED RESERVES		
Balance at January 1, 1999	340,135	2,723
Revisions of estimates	5,699	976
Extensions and discoveries	46,739	213
Production	(38,890)	(623)
Balance at December 31, 1999	353,683	3,289
Revisions of estimates	16,523	504
Extensions and discoveries	50,351	234
Production	(41,546)	(579)
Balance at December 31, 2000	379,011	3,448
Revisions of estimates	(11,465)	275
Extensions and discoveries	76,042	479
Production	(37,907)	(515)
Balance at December 31, 2001	405,681	3,687

QUESTAR MARKET RESOURCES, INC. AND SUBSIDIARIES
Schedule of Valuation and Qualifying Accounts
December 31, 2001
(In Thousands)

Column A	Column B	Column C	Column D	Column E
Description	Beginning Balance	Amounts charged to expense	Deductions for accounts written off	Ending Balance
YEAR ENDED DECEMBER 31, 2001				
Allowance for bad debts	$1,775	$1,229	$155	$2,849
YEAR ENDED DECEMBER 31, 2000				
Allowance for bad debts	1,350	431	6	1,775
YEAR ENDED DECEMBER 31, 1999				
Allowance for bad debts	3,253	25	1,928	1,350

GLOSSARY OF COMMONLY USED OIL AND GAS TERMS

"Bbl" means barrel. One barrel is the equivalent of 42 standard U.S. gallons.

"Bcf" means billion cubic feet, a common unit of measurement of natural gas.

"Bcfe" means billion cubic feet of natural gas equivalents. Oil volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil to six thousand cubic feet of natural gas.

"Btu" means British thermal unit, measured as the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

"Completion" means the completion of the processes necessary before production of oil or natural gas occurs (e.g., perforating the casing; installing permanent equipment in the well; or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Development well" means a well drilled into a known producing formation in a previously discovered field.

"Dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Dth" means decatherms or ten therms. One decatherm equals one million Btu.

"EMMDth" means million decatherms of natural gas equivalents.

"Exploratory well" means a well drilled into a previously untested geologic structure to determine the presence of oil or gas.

"Gross" natural gas and oil wells or "gross" acres equals the number of wells or acres in which we have an interest.

"MBbls" means thousand barrels.

"Mcf" means thousand cubic feet.

"Mcfe" means thousand cubic feet of natural gas equivalents.

"MDths" means thousand decatherms.

"MMBbls" means million barrels.

"MMBtu" means million British thermal units.

"MMcf" means million cubic feet.

"MMcfe" means million cubic feet of natural gas equivalents.

"MMDth" means million decatherms.

"Net" gas and oil wells or "net" acres are determined by multiplying gross wells or acres by our working interest in those wells or acres.

"NGL" means natural gas liquids.

"Proved reserves" means those quantities of natural gas and crude oil, condensate, and natural gas liquids on a net revenue interest basis, which geological and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions. "Proved developed reserves" include proved developed producing reserves and proved developed behind-pipe reserves. "Proved developed producing reserves" include only those reserves expected to be recovered from existing completion intervals in existing wells. "Proved undeveloped reserves" include those 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.

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

"Working interest" means an interest that gives the owner the right to drill, produce, and conduct operating activities on a property and receive a share of any production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March, 2002.

QUESTAR MARKET RESOURCES, INC.
(Registrant)

By /s/ G. L. Nordloh

G. L. Nordloh
President & Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

/s/ G. L. Nordloh G. L. Nordloh	President & Chief Executive Officer; Director (Principal Executive Officer)
/s/ S. E. Parks S. E. Parks	Vice President, Treasurer and Chief Financial Officer (Principal Financial Officer)
/s/ B. Kurtis Watts B. Kurtis Watts	Manager, Accounting (Principal Accounting Officer)
*R. D. Cash	Chairman of the Board; Director
*Teresa Beck	Director
*Patrick J. Early	Director
*James A. Harmon	Director
*G. L. Nordloh	Director
*Keith O. Rattie	Director
MARCH 27, 2002 Date	*By /s/ G. L. Nordloh G. L. Nordloh, Attorney in Fact

EXHIBIT INDEX

Exhibit Number	Description
3.1.*	Articles of Incorporation dated April 27, 1988 for Utah Entrada Industries, Inc. (Exhibit No. 3.1. to the Company's Form 10 dated April 12, 2000.)
3.2.*	Articles of Merger, dated May 20, 1988, of Estrada Industries, Inc., a Delaware corporation and Utah Entrada Industries, Inc a Utah corporation. (Exhibit No. 3.2. to the Company's Form 10 dated April 12, 2000.)
3.3.*	Articles of Amendment dated August 31, 1998, changing the name of Entrada Industries, Inc. to Questar Market Resources, Inc. (Exhibit No 3.3 to the Company's Form 10 dated April 12, 2000.)
3.4.*	Bylaws (as amended effective February 8, 2000.) (Exhibit No 3.4. to the Company's Form 10 dated April 12, 2000.)
4.1.*	Indenture dated as of March 1, 2001, between the Questar Market Resources, Inc. and Bank One, NA, as Trustee for the Company's 7 1/2% Notes due 2011. (Exhibit No. 4.01 to the Company's Current Report on Form 8-K dated March 6, 2001.)
4.2.*	Form of 7 1/2% Notes due 2011. (Exhibit NO. 4.02, to the Company's Current Report on Form 8-K dated March 6, 2001.)
4.4.	U.S. Credit Agreement, dated April 19, 1999, by and among Questar Market Resources, Inc., as U.S. borrower, NationBank, N.A., as U.S. agent, and certain financial institutions, as lenders, with the First Amendment dated November 30, 1999, the Fourth Amendment dated April 17, 2000, the Fifth Amendment dated October 6, 2000, and the Sixth Amendment dated February 9, 2001. (Exhibit No. 4.1. to the Company's Form 10 dated April 12, 2000, for the U.S. Credit Agreement, and the First, Second and Third Amendments; Exhibit No 4.1. to the Company's Form 10/A dated November 9, 2000, for the Fourth and Fifth Amendments. Exhibits No. 4.3. to the Company's Form 10-K Annual Report for 2000 for the Sixth Amendment.) The Seventh Amendment dated April 16, 2001, is filed as Exhibit 4.4 to this report.
4.5	Long-term debt instruments with principal amounts not exceeding 10 percent of QMR's total consolidated assets are not filed as exhibits. The Company will furnish a copy of these agreements to the Commission upon request.
10.1.*	Stipulation and Agreement, dated October 14, 1981, executed by

Mountain Fuel Supply Company [Questar Gas Company]; Wexpro Company; Utah Department of Business Regulations, Division of Public Utilities; the Utah Committee of Consumer

Services; and the staff of the Public Service Commission of Wyoming. (Exhibit No. 10(a) to Questar Gas Company's Form 10-K Annual Report for 1981.)

10.2.* Stock Purchase Agreement among the Company, Shenandoah Energy and Shenandoah Energy's stockholders. (Exhibit No. 10.2, to the Company's Current Report on Form 8-K dated July 31, 2001.)

12 Ratio of earnings to fixed charges.

21. Subsidiary Information.

23. Consent of Independent Auditors.

24. Power of Attorney.

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

(b) The Company filed a Current Report on Form 8-K dated October 12, 2001 that contained the financial statements and pro forma information required as a result of the Company's acquistion of Shenandoah Energy.

EXHIBIT 4.4

SEVENTH AMENDMENT TO US CREDIT AGREEMENT

THIS SEVENTH AMENDMENT TO US CREDIT AGREEMENT (herein called the "Amendment") made as of April 16, 2001 (herein called the "Effective Date"), by and among Questar Market Resources, Inc., a Utah corporation ("US Borrower"), Bank of America, N.A., individually and as administrative agent for the Lenders as defined below ("US Agent"), and the undersigned Lenders.

W I T N E S S E T H:

WHEREAS, US Borrower, US Agent and the lenders as signatories thereto (the "Lenders") entered into that certain US Credit Agreement dated as of April 19, 1999, as amended by that certain First Amendment to US Credit Agreement dated as of May 17, 1999, as amended by that certain Second Amendment to US Credit Agreement dated as of July 30, 1999, as amended by that certain Third Amendment to US Credit Agreement dated as of November 30, 1999, as amended by that certain Fourth Amendment to US Credit Agreement dated as of April 17, 2000, and as amended by that certain Fifth Amendment to US Credit Agreement dated as of October 6, 2000, and as amended by that certain Sixth Amendment to US Credit Agreement dated as of February 9, 2001 (the "Original Agreement"), for the purpose and consideration therein expressed, whereby the Lenders became obligated to make loans to US Borrower as therein provided; and

WHEREAS, US Borrower, US Agent and the undersigned Lenders desire to amend the Original Agreement for the purposes as provided herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Agreement, in consideration of the loans which may hereafter be made by Lenders to US Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I.

DEFINITIONS AND REFERENCES

Section 1.1. TERMS DEFINED IN THE ORIGINAL AGREEMENT. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Agreement shall have the same meanings whenever used in this Amendment.

Section 1.2. OTHER DEFINED TERMS. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

"AMENDMENT" means this Seventh Amendment to US Credit Agreement.

"US CREDIT AGREEMENT" means the Original Agreement as amended hereby.

ARTICLE II.

AMENDMENTS TO ORIGINAL AGREEMENT

Section 2.1. AMENDMENT TO ANNEX I. The following definitions set forth in Annex I to the Original Agreement are hereby amended in their entirety to read as follows:

"'364-DAY COMMITMENT FEE RATE' means, on any date, the number of Basis Points per annum set forth below based on the Applicable Rating Level on such date:

Applicable Rating Level	Applicable 364-Day Commitment Fee Rate
Level I	8.5
Level II	10.0
Level III	12.5
Level IV	15.0
Level V	17.0
Level VI	22.5

Level VII	27.5"

"'APPLICABLE MARGIN'

(a) means when used with respect to Tranche A Loans in the US Agreement on any date, the number of Basis Points per annum set forth below based on the Applicable Rating Level on such date:

Applicable Rating Level	Applicable Margin
Level I	30.0
Level II	35.0
Level III	45.0
Level IV	60.0
Level V	75.0
Level VI	100.0
Level VII	125.0

(b) means when used in the Canadian Agreement and when used with respect to Tranche B Loans in the US Agreement on any date, the number of Basis Points per annum set forth below based on the Applicable Rating Level on such date:

Applicable Rating Level	Applicable Margin
Level I	30.0
Level II	40.0
Level III	50.0
Level IV	75.0
Level V	87.5
Level VI	100.0
Level VII	125.0

In the event that the Canadian Revolving Loans convert into Canadian Term Loans pursuant to Section 1.7 of the Canadian Agreement, then as of April 20, 2004, and at all times thereafter the Applicable Margin as set forth above on such Canadian Term Loans shall increase by fifteen (15) Basis Points per annum. Changes in the Applicable Margin will occur automatically without prior notice as changes in the Applicable Rating Level occur.

US Agent will give notice promptly to Borrowers and the Lenders of changes in the Applicable Margin."

"'BA DISCOUNT RATE' means, in respect of a BA being accepted by a Lender on any date, (i) for a Lender that is listed in Schedule I to the BANK ACT (Canada), the average bankers' acceptance rate as quoted on Reuters CDOR page (or such other page as may, from time to time, replace such page on that service for the purpose of displaying quotations for bankers' acceptances accepted by leading Canadian financial institutions) at approximately 10:00 a.m. (Toronto time) on such drawdown date for bankers' acceptances having a comparable maturity date as the maturity date of such BA (the "CDOR Rate"); or, if such rate is not available at or about such time, the average of the bankers' acceptance rates (expressed to five decimal places) as quoted to the Agent by the Schedule I BA Reference Banks as of 10:00 a.m. (Toronto time) on such drawdown date for bankers' acceptances having a comparable maturity date as the maturity date of such BA; and (ii) for a Lender that is listed in Schedule II to the BANK ACT (Canada) or a Lender that is listed in Schedule III to the Bank Act (Canada) that is not subject to the restrictions and requirements referred to in subsection 524 (2) of the Bank Act (Canada), the rate established by the Canadian Agent to be the lesser of (A) the CDOR Rate plus 10 Basis Points; and (B) the average of the bankers' acceptance rates (expressed to five decimal places) as quoted to the Canadian Agent by the Schedule II BA Reference Banks as of 10:00 a.m. (Toronto time) on such drawdown date for bankers' acceptances having a comparable maturity date as the maturity date of such BA."

"'Canadian Maximum Credit Amount' means the Canadian Dollar Exchange Equivalent of US $58,333,333.33; provided that the Canadian Maximum Credit Amount may be increased up to US $70,000,000 pursuant to Section 1.1(b) of the Canadian Agreement."

"'CONVERSION DATE' means April 15, 2002, or such later day to which the Conversion Date is extended pursuant to Section 1.6 of the Canadian Agreement."

"'MAJORITY LENDERS' means (i) when used in the US Agreement, Lenders whose aggregate Percentage Shares under the US Agreement equal or exceed sixty-six and two thirds percent (66 2/3%), and (ii) when used in the Canadian Agreement, Lenders whose aggregate Percentage Shares under the Canadian Agreement equal or exceed sixty-six and two thirds percent (66 2/3%)."

"'PERCENTAGE SHARE' means

(a) under the US Agreement with respect to any Lender (i) when no US Loans are outstanding, the percentage set forth below such Lender's name on the Lenders Schedule as its Percentage Share under the US Agreement, as modified by assignments of a Lender's rights and obligations under the US Agreement made by or to such Lender in accordance with the terms of the US Agreement or pursuant to Section 1.1(f) of the US Agreement, and (ii) when used otherwise, the percentage obtained by dividing (x) the sum of the unpaid principal balance of such Lender's US Loans and such Lender's Percentage Share of the US LC Obligations, by (y) the sum of the aggregate unpaid principal balance of all US Loans at such time plus the aggregate amount of all US LC Obligations outstanding at such time;

(b) under the Canadian Agreement with respect to any Lender (i) when used in Article I or Article II of the Canadian Agreement, in any Borrowing Notice thereunder or when no Canadian Advances are outstanding, the percentage set forth below such Lender's name on the Lenders Schedule as its Percentage Share under the Canadian Agreement, as modified by assignments of a Lender's rights and obligations under the Canadian Agreement made by or to such Lender in accordance with the terms of the Canadian Agreement or pursuant to Section 1.1(b) of the Canadian Agreement, and (ii) when used otherwise, the percentage obtained by dividing (x) the sum of the unpaid principal balance of such Lender's Canadian Advances and such Lender's Percentage Share of the Canadian LC Obligations, by (y) the sum of the aggregate unpaid principal balance of all Canadian Advances at such time plus the aggregate amount of all Canadian LC Obligations outstanding at such time; and

(c) when used in any Loan Document with respect to all Lenders under the US Agreement and the Canadian Agreement, (i) for any Lender under the US Agreement, the percentage obtained by dividing such Lender's Percentage Share of the US Facility Usage by the Aggregate Facility Usage, and (ii) for any Lender under the Canadian Agreement, the percentage obtained by dividing such Lender's Percentage Share of the Canadian Facility Usage by the Aggregate Facility Usage."

"'PERMITTED LIENS' means:

(a) operators' liens under customary operating agreements, liens arising under gas transportation and purchase agreements on the gas being transported or processed which secure related gas transportation and processing fees only, statutory Liens for taxes, statutory mechanics' and materialmen's Liens, and other similar statutory Liens, provided such Liens secure only Liabilities which are not delinquent or which are being contested as provided in Section 6.7 of the US Agreement or Section 6.7 of the Canadian Agreement;

(b) Liens on any oil and gas properties which neither have developed reserves (producing or non-producing) properly attributable thereto nor are otherwise held under lease by production of other reserves;

(c) Liens on the Restricted Persons' office facilities;

(d) Liens on property securing non-recourse debt permitted under Section 7.1(f) of the US Agreement and Section 7.1(f) of the Canadian Agreement which is acquired with proceeds or developed with proceeds of the non-recourse debt; and

(e) Liens to secure the Obligations provided that nothing in this definition shall in and of itself constitute or be deemed to constitute an agreement or acknowledgment by the US Agent or the Canadian Agent or any Lender that the Indebtedness subject to or secured by any such Permitted Lien ranks (apart from the effect of any Lien included in or inherent in any such Permitted Liens) in priority to the Obligations."

"'REQUIRED LENDERS' means (i) when used in the US Agreement, Lenders whose aggregate Percentage Shares under the US Agreement equal or exceed fifty percent (50%), and (ii) when used in the Canadian Agreement, Lenders whose aggregate Percentage Shares under the Canadian Agreement equal or exceed fifty percent (50%)."

"'TRANCHE B CONVERSION DATE' means April 15, 2002, or such later day to which the Tranche B Conversion Date is extended pursuant to Section 1.1 of the US Agreement."

"'TRANCHE B MAXIMUM CREDIT AMOUNT' means $41,666,666.67; provided that the Tranche B Maximum Credit Amount may be increased up to $50,000,000 pursuant to Section 1.1(f) of the US Agreement."

Section.2. ADDITIONAL DEFINITIONS. The following definitions are hereby added to Annex I of the Original Agreement, in alphabetical order, to read as follows:

"'AGGREGATE FACILITY USAGe' means, at the time in question, the sum of (i) the Canadian Facility Usage plus (ii) the US Facility Usage."

"'TRANCHE A LENDERS' means Lenders designated as Tranche A Lenders on the Lenders Schedule."

"'TRANCHE A PERCENTAGE SHARE' means with respect to any Tranche A Lender (i) when used in Article I of the US Agreement or in Article II of the US Agreement, in any Borrowing Notice thereunder or when no Tranche A Loans are outstanding, the Tranche A percentage set forth below such Tranche A Lender's name on the Lenders Schedule as modified by assignments of a Tranche A Lender's rights and obligations under the US Agreement made by or to such Lender in accordance with the terms of the US Agreement, and (ii) when used otherwise, the percentage obtained by dividing (x) the sum of the unpaid principal balance of such Lender's Tranche A Loans and such Lender's Percentage Share of the US LC Obligations, by (y) the sum of the aggregate unpaid principal balance of all Tranche A Loans at such time plus the aggregate amount of all US LC Obligations outstanding at such time."

"'TRANCHE A REQUIRED LENDERS' means Tranche A Lenders whose aggregate Tranche A Percentage Shares equal or exceed fifty percent (50%)."

"'TRANCHE B LENDERS' means Lenders designated as Tranche B Lenders on the Lenders Schedule."

"'TRANCHE B PERCENTAGE SHARE' means with respect to any Tranche B Lender (i) when used in Article I of the US Agreement, in any Borrowing Notice thereunder or when no Tranche B Loans are outstanding, the Tranche B percentage set forth below such Tranche B Lender's name on the Lenders Schedule as modified by assignments of a Tranche B Lender's rights and obligations under the US Agreement made by or to such Lender in accordance

with the terms of the US Agreement, and (ii) when used otherwise, the percentage obtained by dividing (x) the sum of the unpaid principal balance of such Lender's Tranche B Loans, by (y) the sum of the aggregate unpaid principal balance of all Tranche B Loans."

"'TRANCHE B REQUIRED LENDERS' means Tranche B Lenders whose aggregate Tranche B Percentage Shares equal or exceed fifty percent (50%)."

Section.3. COMMITMENT TO LEND; US NOTES. Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

"Section 1.1. COMMITMENTS TO LEND; US NOTES.

(a) TRANCHE A. Subject to the terms and conditions hereof, each Lender severally agrees to make loans to US Borrower (herein called such Tranche A Lender's "Tranche A Loans") upon US Borrower's request from time to time during the US Facility Commitment Period, provided that (i) subject to Sections 3.3, 3.4 and 3.5, all Tranche A Lenders are requested to make Tranche A Loans of the same Type in accordance with their respective Percentage Shares and as part of the same Borrowing, (ii) the US Facility Usage shall never exceed the US Maximum Credit Amount, (iii) such Tranche A Lender's Percentage Share of the US Facility Usage shall never exceed such Tranche A Lender's Percentage Share of the US Maximum Credit Amount (calculated excluding Competitive Bid Loans), and (iv) such Tranche A Lender's Percentage Share of the Tranche A Facility Usage shall never exceed such Tranche A Lender's Percentage Share of the Tranche A Maximum Credit Amount. The aggregate amount of all Tranche A Loans in any Borrowing must be an integral multiple of US $100,000 which equals or exceeds US $200,000 or, if less, must equal the unadvanced portion of the US Maximum Credit Amount. The obligation of US Borrower to repay to each Tranche A Lender the aggregate amount of all Tranche A Loans made by such Tranche A Lender, together with interest accruing in connection therewith, shall be evidenced by a single promissory note (herein called such Tranche A Lender's "Tranche A Note") made by US Borrower payable to the order of such Tranche A Lender in the form of Exhibit A-1 with appropriate insertions. The amount of principal owing on any Tranche A Lender's Tranche A Note at any given time shall be the aggregate amount of all Tranche A Loans theretofore made by such Tranche A Lender minus all payments of principal theretofore received by such Tranche A Lender on such Tranche A Note. Interest on each Tranche A Note shall accrue and be due and payable as provided herein and therein. Each Tranche A Note shall be due and payable as provided herein and therein, and shall be due and payable in full on the US Facility Maturity Date. Subject to the terms and conditions hereof, US Borrower may borrow, repay, and reborrow Tranche A Loans under the US Agreement during the US Facility Commitment Period. US Borrower may have no more than ten Borrowings of US Dollar Eurodollar Loans (including Tranche A Loans and Tranche B Loans) outstanding at any time.

(b) TRANCHE B. Subject to the terms and conditions hereof, each Tranche B Lender severally agrees to make loans to US Borrower (herein called such Tranche B Lender's "Tranche B Loans") upon US Borrower's request from time to time during the

Tranche B Revolving Period, provided that (i) subject to Sections 3.3, 3.4 and 3.5, all Tranche B Lenders are requested to make Tranche B Loans of the same Type in accordance with their respective Percentage Shares and as part of the same Borrowing, (ii) the US Facility Usage shall never exceed the US Maximum Credit Amount , (iii) such Tranche B Lender's Percentage Share of the US Facility Usage shall never exceed such Tranche B Lender's Percentage Share of the US Maximum Credit Amount (calculated excluding Competitive Bid Loans), and (iv) such Tranche B Lender's Percentage Share of the Tranche B Facility Usage shall never exceed such Tranche B Lender's Percentage Share of the Tranche B Maximum Credit Amount. The aggregate amount of all Tranche B Loans in any Borrowing must be an integral multiple of US $100,000 which equals or exceeds US $200,000 or, if less, must equal the unadvanced portion of the US Maximum Credit Amount. The obligation of US Borrower to repay to each Tranche B Lender the aggregate amount of all Tranche B Loans made by such Tranche B Lender, together with interest accruing in connection therewith, shall be evidenced by a single promissory note (herein called such Tranche B Lender's "Tranche B Note") made by US Borrower payable to the order of such Tranche B Lender in the form of Exhibit A-2 with appropriate insertions. The amount of principal owing on any Tranche B Lender's Tranche B Note at any given time shall be the aggregate amount of all Tranche B Loans theretofore made by such Tranche B Lender minus all payments of principal theretofore received by such Tranche B Lender on such Tranche B Note. Interest on each Tranche B Note shall accrue and be due and payable as provided herein and therein. Each Tranche B Note shall be due and payable as provided herein and therein, and shall be due and payable in full on the Tranche B Maturity Date. Subject to the terms and conditions hereof, US Borrower may borrow, repay, and reborrow Tranche B Loans under the US Agreement during the Tranche B Revolving Period. US Borrower may have no more than ten Borrowings of US Dollar Eurodollar Loans (including Tranche A Loans and Tranche B Loans) outstanding at any time.

(c) EXTENSION OF CONVERSION DATE.

(i) US Borrower may, at its option and from time to time during the Tranche B Revolving Period, request an offer to extend the Tranche B Revolving Period by delivering to US Agent a Request for an Offer of Extension not more than sixty days prior to the then current Tranche B Conversion Date. US Agent shall forthwith provide a copy of the Request for an Offer of Extension to each of the Tranche B Lenders. Upon receipt by each Tranche B Lender from US Agent of an executed Request for an Offer of Extension, each Tranche B Lender shall, within thirty days after the date such Tranche B Lender receives such request from US Agent, either:

(1) notify US Agent of its acceptance of the Request for an Offer of Extension, and the terms and conditions, if any, upon which such Tranche B Lender is prepared to extend the Tranche B Conversion Date; or

(2) notify US Agent that the Request for an Offer of Extension has been denied, such notice to forthwith be forwarded by US Agent to US

Borrower to allow US Borrower to seek a replacement Tranche B Lender pursuant to Section 1.1(e) (any Tranche B Lender giving notice of such denial is herein called a "Non-Accepting Tranche B Lender"). The failure of a Tranche B Lender to so notify US Agent within such thirty day period shall be deemed to be notification by such Tranche B Lender to US Agent that such Tranche B Lender has denied US Borrower's Request for an Offer of Extension.

(ii) Provided that all Tranche B Lenders provide notice to US Agent under Section 1.1(c)(i) that they accept the Request for an Offer of Extension, or if there are Non-Accepting Tranche B Lenders, such Tranche B Lenders shall have been repaid pursuant to Section 1.1(e) or replacement Tranche B Lenders shall have become parties hereto pursuant to Section 1.1(e) and shall have accepted the Request for an Offer of Extension, such acceptance having common terms and conditions, US Agent shall deliver to US Borrower an Offer of Extension incorporating such terms and conditions. Such offer shall be open for acceptance by US Borrower until the fifth Business Day immediately preceding the then current Tranche B Conversion Date. Upon written notice by US Borrower to US Agent accepting an outstanding Offer of Extension and agreeing to the terms and conditions, if any, specified therein (the date of such notice of acceptance in this Section 1.1 being called the "Extension Date"), the Tranche B Conversion Date shall be extended to the date 364 days from the Extension Date and the terms and conditions specified in such Offer of Extension shall be immediately effective.

(iii) US Borrower understands that the consideration of any Request for an Offer of Extension constitutes an independent credit decision which each Tranche B Lender retains the absolute and unfettered discretion to make and that no commitment in this regard is hereby given by a Tranche B Lender and that any offer to extend the Tranche B Conversion Date may be on such terms and conditions in addition to those set out herein as the extending Tranche B Lenders stipulate.

(d) CONVERSION TO TRANCHE B TERM LOAN. Effective at 11:59 p.m. Dallas, Texas time on the day immediately preceding the Tranche B Conversion Date, (i) each Tranche B Lender's obligation to make new Tranche B Loans shall be canceled automatically, and (ii) each Tranche B Lender's Tranche B Loans shall become term loans maturing on the Tranche B Maturity Date.

(e) NON-ACCEPTING TRANCHE B LENDER. Provided that Tranche B Lenders whose Percentage Shares represent more than 50% but less than 100% of the US Maximum Credit Amount provide notice to US Agent under Section 1.1(c)(i) that they accept the Request for an Offer of Extension, on notice of US Borrower to US Agent, US Borrower shall be entitled to choose any of the following in respect of each Non-Accepting Tranche B Lender prior to the expiration of the Tranche B Revolving Period, provided that if US Borrower does not make an election prior to the expiration of the Tranche B Revolving Period, US Borrower shall be deemed to have irrevocably elected to exercise the provisions of Section 1.1(e)(i):

(i) the Non-Accepting Tranche B Lender's obligations to make US Loans shall be canceled as of the Extension Date, the US Maximum

Credit Amount shall be reduced by the amount so canceled, and on or prior to the Extension Date the US Borrower shall repay in full all Obligations then outstanding to the Non-Accepting Tranche B Lender (as defined in Section 1.1(c)(i)(2)), or

(ii) replace the Non-Accepting Tranche B Lender by reaching satisfactory arrangements with one or more existing Tranche B Lenders or new Tranche B Lenders, for the purchase, assignment and assumption of all Canadian Obligations and US Obligations of the Non-Accepting Tranche B Lender, provided that any new Tranche B Lender, with, if necessary, any Affiliate, shall take a pro rata assignment of both Canadian Obligations and US Obligations, and such Non-Accepting Tranche B Lender shall be obligated to sell such Obligations in accordance with such satisfactory arrangements.

In connection with any such replacement of a Tranche B Lender pursuant to this Section 1.1(e), US Borrower shall pay all costs that would have been due to such Tranche B Lender pursuant to Section 3.6 if such Tranche B Lender's US Loans had been prepaid at the time of such replacement.

(f) INCREASE IN COMMITMENTS. During the Tranche B Revolving Period, the Tranche A Maximum Credit Amount, the Tranche B Maximum Credit Amount, the US Maximum Credit Amount and the Canadian Maximum Credit Amount may be increased, pro rata, by an aggregate amount of $10,000,000 or any higher integral multiple thereof not to exceed $50,000,000 at the request of US Borrower and with the prior written consent of the US Agent and the Canadian Agent, which consent shall not be unreasonably withheld, and without the consent of any Lender provided that a new Lender becomes a party to the Credit Agreement with the same Percentage Share under Tranche B of the US Credit Agreement and the Canadian Credit Agreement, and that such Lender agrees to all of the terms and conditions of the US Loan Documents and the Canadian Loan Documents. Each of US Agent and Canadian Agent are hereby authorized to execute and deliver amendments to the Loan Documents to effectuate the foregoing on behalf of all Lenders."

Section.4. TRANCHE A COMMITMENT FEES. Section 1.5(a)(ii) of the Original Agreement is hereby amended in its entirety to read as follows:

"(ii) TRANCHE A COMMITMENT FEES. In consideration of each Tranche A Lender's commitment to make Tranche A Loans under this Agreement, US Borrower will pay to US Agent for the account of each Tranche A Lender a commitment fee determined on a daily basis by applying the Five-Year Commitment Fee Rate to its Tranche A Percentage Share of the amount by which the Tranche A Maximum Credit Amount exceeds the Tranche A Facility Usage on each day during the US Facility Commitment Period. This commitment fee shall be due and payable in arrears on the fifteenth day after the end of each Fiscal Quarter and at the end of the US Facility Commitment Period."

Section 2.5. TRANCHE B COMMITMENT FEES. Section 1.5(b)(ii) of the Original Agreement is hereby amended in its entirety to read as follows:

"(ii) COMMITMENT FEES. In consideration of each Tranche B Lender's commitment to make Tranche B Loans under this Agreement, US Borrower will pay to US Agent for the account of each Tranche B Lender a commitment fee determined on a daily basis by applying the 364-Day Commitment Fee Rate to its Tranche B Percentage Share of the amount by which the Tranche B Maximum Credit Amount exceeds the outstanding principal balance of the Tranche B Loans on each day during the period from the date hereof until the Tranche B Maturity Date. This commitment fee shall be due and payable in arrears on the fifteenth day after the end of each Fiscal Quarter and on the Tranche B Maturity Date."

Section 2.6. UTILIZATION FEES. Section 1.5(c) of the Original Agreement is hereby amended in its entirety to read as follows:

"(c) UTILIZATION FEES. During the period from April 16, 2001, until the latest of the Tranche B Conversion Date, the US Facility Maturity Date, and the Conversion Date under the Canadian Agreement, US Borrower will pay to US Agent for the account of each Lender under the US Agreement and the Canadian Agreement, a utilization fee for each day on which the Aggregate Facility Usage exceeds thirty three and one-third percent (33 1/3%) of the sum of (i) the US Maximum Credit Amount plus (ii) the Canadian Maximum Credit Amount; PROVIDED THAT, if the Canadian Loans or Tranche B Loans have been converted to term loans, they shall be excluded from the calculation of utilization fees. The amount of the utilization fee shall be determined on a daily basis by applying the Utilization Fee Rate to each such Lender's Percentage Share of the Aggregate Facility Usage on each such day. This utilization fee shall be due and payable in arrears on each Interest Payment Date for US Base Rate Loans and at the end of the US Facility Commitment Period."

Section 2.7. LETTERS OF CREDIT. Sections 2.3 and 2.4 of the Original Agreement are hereby amended in their entirety to read as follows:

"Section 2.3 REIMBURSEMENT AND PARTICIPATIONS.

(a) REIMBURSEMENT BY US BORROWER. If the beneficiary of any Letter of Credit issued hereunder makes a draft or other demand for payment thereunder then Tranche A Loans that are US Base Rate Loans shall be made by Tranche A Lenders to US Borrower in the amount of such draft or demand notwithstanding the fact that one or more conditions precedent to the making of such US Base Rate Loans may not have been satisfied. Such US Base Rate Loans shall be made concurrently with US LC Issuer's payment of such draft or demand without any request therefor by US Borrower and shall be immediately used by US LC Issuer to repay the amount of the resulting Matured US LC Obligation.

(b) PARTICIPATION BY TRANCHE A LENDERS. US LC Issuer irrevocably agrees to grant and hereby grants to each Tranche A Lender, and to induce US LC Issuer to issue Letters of

Credit hereunder, each Tranche A Lender irrevocably agrees to accept and purchase and hereby accepts and purchases from US LC Issuer, on the terms and conditions hereinafter stated and for such Tranche A Lender's own account and risk, an undivided interest equal to its Tranche A Percentage Share of US LC Issuer's obligations and rights under each Letter of Credit issued hereunder and the amount of each Matured US LC Obligation paid by US LC Issuer thereunder. Each Tranche A Lender unconditionally and irrevocably agrees with US LC Issuer that, if a Matured US LC Obligation is paid under any Letter of Credit issued hereunder for which US LC Issuer is not reimbursed in full, whether pursuant to Section 2.3(a) above or otherwise, such Tranche A Lender shall (in all circumstances and without set-off or counterclaim) pay to US LC Issuer on demand, in immediately available funds at US LC Issuer's address for notices hereunder, its Tranche A Percentage Share of such Matured US LC Obligation (or any portion thereof which has not been reimbursed by US Borrower). Each Tranche A Lender's obligation to pay US LC Issuer pursuant to the terms of this subsection is irrevocable and unconditional. If any amount required to be paid by any Tranche A Lender to US LC Issuer pursuant to this subsection is paid by such Tranche A Lender to US LC Issuer within three Business Days after the date such payment is due, US LC Issuer shall in addition to such amount be entitled to recover from such Tranche A Lender, on demand, interest thereon calculated from such due date at the Federal Funds Rate. If any amount required to be paid by any Tranche A Lender to US LC Issuer pursuant to this subsection is not paid by such Tranche A Lender to US LC Issuer within three Business Days after the date such payment is due, US LC Issuer shall in addition to such amount be entitled to recover from such Tranche A Lender, on demand, interest thereon calculated from such due date at the Default Rate.

(c) DISTRIBUTIONS TO PARTICIPANTS. Whenever US LC Issuer has in accordance with this section received from any Tranche A Lender payment of its Tranche A Percentage Share of any Matured US LC Obligation, if US LC Issuer thereafter receives any payment of such Matured US LC Obligation or any payment of interest thereon (whether directly from US Borrower or by application of LC Collateral or otherwise, and excluding only interest for any period prior to US LC Issuer's demand that such Tranche A Lender make such payment of its Tranche A Percentage Share), US LC Issuer will distribute to such Tranche A Lender its Tranche A Percentage Share of the amounts so received by US LC Issuer; PROVIDED, HOWEVER, that if any such payment received by US LC Issuer must thereafter be returned by US LC Issuer, such Tranche A Lender shall return to US LC Issuer the portion thereof which US LC Issuer has previously distributed to it.

(d) CALCULATIONS. A written advice setting forth in reasonable detail the amounts owing under this section, submitted by US LC Issuer to US Borrower or any Tranche A Lender from time to time, shall be conclusive, absent manifest error, as to the amounts thereof."

"Section 2.4 LETTER OF CREDIT FEES. In consideration of US LC Issuer's issuance of any Letter of Credit, US Borrower agrees to pay to US LC Issuer for its own account, a letter of credit fronting fee at a rate equal to 12.5 Basis Points per annum, prorated for the term of the Letter of Credit, multiplied by the face amount of such Letter of Credit, payable on the

date of issuance, and (b) to US Agent, for the account of all Tranche A Lenders in accordance with their respective Tranche A Percentage Shares, a letter of credit issuance fee calculated by applying the Applicable Margin to the face amount of all Letters of Credit outstanding on each day, payable in arrears on the last day of each Fiscal Quarter."

Section 2.8. RELIANCE BY US AGENT. The third sentence of Section 9.2 of the Original Agreement is hereby amended in its entirety to read as follows:

"As to any matters not expressly provided for by this Agreement, US Agent shall not be required to exercise any discretion or take any action, but shall be required to act or to refrain from acting (and shall be fully protected in so acting or refraining from acting) upon the instructions of the Tranche A Required Lenders, Tranche B Required Lenders or Required Lenders, as provided in this Agreement, and such instructions shall be binding on all of the Lenders, Tranche A Lenders or Tranche B Lenders, respectively; PROVIDED, HOWEVER, that US Agent shall not be required to take any action that exposes US Agent to personal liability or that is contrary to any Loan Document or applicable Law or unless it shall first be indemnified to its satisfaction by the Lenders against any and all liability and expense which may be incurred by it by reason of taking any such action."

Section 2.9. PRO RATA. The fourth sentence of Section 9.11 of the Original Agreement is hereby amended in its entirety to read as follows:

"Section 9.11 LENDERS TO REMAIN PRO RATA. It is the intent of all parties hereto that, except for Competitive Bid Loans and matters related thereto, the Tranche B Percentage Share of each Tranche B Lender and such Lender's Percentage Share of the Canadian Obligations shall be substantially the same at all times during the term of this Agreement. All subsequent assignments and adjustments of the interests of the Lenders in Tranche B Loans and in the Canadian Obligations will be made so as to maintain such a pro rata arrangement; provided that for the purposes of determining these pro rata shares, any Percentage Share held by any Lender's Affiliates shall be included in determining the interests of such Lender."

Section 2.10. WAIVERS AND AMENDMENTS. The fourth sentence of Section 10.1 of the Original Agreement is hereby amended in its entirety to read as follows:

"This Agreement and the other US Loan Documents set forth the entire understanding between the parties hereto with respect to the transactions contemplated herein and therein and supersede all prior discussions and understandings with respect to the subject matter hereof and thereof, and no waiver, consent, release, modification or amendment of or supplement to this Agreement or the other US Loan Documents shall be valid or effective against any party hereto unless the same is in writing and signed by (i) if such party is US Borrower, by US Borrower, (ii) if such party is US Agent or US LC Issuer, by such party, (iii) if such party is a Tranche A Lender, by such Tranche A Lender or by US Agent on behalf of Tranche A Lenders with the written consent of Tranche A Required Lenders, (iv) if such party is a Tranche B Lender, by such Tranche B Lender or by US Agent on behalf of

Tranche B Lenders with the written consent of Tranche B Required Lenders and (v) if such party is a Lender, by such Lender or by US Agent on behalf of Lenders with the written consent of Required Lenders (which consent has already been given as to the termination of the US Loan Documents as provided in Section 10.10)."

Section 2.11 LENDERS SCHEDULE. The Lenders Schedule attached to the original Agreement is deleted and Schedule 1 hereto is substituted therefor.

ARTICLE III.

AMENDMENT FEE

Section 3.1. AMENDMENT FEE. In consideration of US Agent and each Lenders' agreement to enter into this Amendment, US Borrower will pay to US Agent for the account of each Lender an amendment fee determined by applying five Basis Points to such Lender's Percentage Share of the Tranche B Maximum Credit Amount. This amendment fee shall be due and payable on the Effective Date of this Amendment.

ARTICLE IV.

CONDITIONS OF EFFECTIVENESS

Section 4.1. EFFECTIVE DATE. This Amendment shall become effective as of the date first above written when, and only when, US Agent shall have received, at US Agent's office:

(i) a counterpart of this Amendment executed and delivered by US Borrower and Required Lenders;

(ii) a certificate of the Secretary or Assistant Secretary and of the

President, Chief Financial Officer or Vice President of Administrative Services of US Borrower dated the date of this Amendment certifying: (a) that resolutions adopted in connection with the Original Agreement by the Board of Directors of the US Borrower authorize the execution, delivery and performance of this Amendment by US Borrower, (b) to the names and true signatures of the officers of the US Borrower authorized to sign this Amendment, and (c) that all of the representations and warranties set forth in Article V hereof are true and correct at and as of the time of such effectiveness; and

(iii) all fees and reimbursements to be paid to US Agent pursuant to any US Loan Documents, or otherwise due US Agent, including fees and disbursements of US Agent's attorneys.

ARTICLE V.

REPRESENTATIONS AND WARRANTIES

Section 5.1. REPRESENTATIONS AND WARRANTIES OF BORROWER. In order to induce US Agent and Lenders to enter into this Amendment, US Borrower represents and warrants to US Agent that:

(a) The representations and warranties contained in Article V of the Original Agreement are true and correct at and as of the time of the effectiveness hereof.

(b) US Borrower has duly taken all action necessary to authorize the execution and delivery by it of this Amendment and to authorize the consummation of the transactions contemplated hereby and the performance of its obligations hereunder. US Borrower is duly authorized to borrow funds under the US Credit Agreement.

(c) The execution and delivery by US Borrower of this Amendment, the performance by US Borrower of its obligations hereunder and the consummation of the transactions contemplated herein do not and will not (a) conflict with any provision of (i) any Law, (ii) the organizational documents of US Borrower, or (iii) any agreement, judgment, license, order or permit applicable to or binding upon US Borrower, or (b) result in the acceleration of any Indebtedness owed by US Borrower, or (c) result in or require the creation of any Lien upon any assets or properties of US Borrower, except as expressly contemplated or permitted in the Loan Documents. Except as expressly contemplated in the Loan Documents no consent, approval, authorization or order of, and no notice to or filing with any Tribunal or third party is required in connection with the execution, delivery or performance by US Borrower of this Amendment or to consummate any transactions contemplated herein.

(d) This Amendment is a legal, valid and binding obligation of US Borrower, enforceable in accordance with its terms, except as such enforcement may be limited by bankruptcy, insolvency or similar Laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application relating to the enforcement of creditor's rights.

ARTICLE VI.

MISCELLANEOUS

Section 6.1. RATIFICATION OF AGREEMENTS. The Original Agreement as hereby amended is hereby ratified and confirmed in all respects. The US Loan Documents, as they may be amended or affected by this Amendment, are hereby ratified and confirmed in all respects. Any reference to the US Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Lenders under the

US Credit Agreement, the US Notes, or any other US Loan Document nor constitute a waiver of any provision of the US Credit Agreement, the US Notes or any other US Loan Document.

Section 6.2. SURVIVAL OF AGREEMENTS; CUMULATIVE NATURE. All of US Borrower's various representations, warranties, covenants and agreements herein shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of the US Loans, and shall further survive until all of the US Obligations are paid in full to each Lender Party and all of Lender Parties' obligations to US Borrower are terminated. All statements and agreements contained in any certificate or instrument delivered by any Restricted Person hereunder or under the US Credit Agreement to any Lender Party shall be deemed representations and warranties by US Borrower or agreements and covenants of US Borrower under this Amendment and under the US Credit Agreement. The representations, warranties, indemnities, and covenants made by Restricted Persons in the US Loan Documents, and the rights, powers, and privileges granted to Lender Parties in the US Loan Documents, are cumulative, and, except for expressly specified waivers and consents, no Loan Document shall be construed in the context of another to diminish, nullify, or otherwise reduce the benefit to any Lender Party of any such representation, warranty, indemnity, covenant, right, power or privilege. In particular and without limitation, no exception set out in this Amendment to any representation, warranty, indemnity, or covenant herein contained shall apply to any similar representation, warranty, indemnity, or covenant contained in any other Loan Document, and each such similar representation, warranty, indemnity, or covenant shall be subject only to those exceptions which are expressly made applicable to it by the terms of the various US Loan Documents.

Section 6.3. LOAN DOCUMENTS. This Amendment is a US Loan Document, and all provisions in the US Credit Agreement pertaining to US Loan Documents apply hereto.

Section 6.4. GOVERNING LAW. This Amendment shall be governed by and construed in accordance the laws of the State of Utah and any applicable laws of the United States of America in all respects, including construction, validity and performance. US Borrower hereby irrevocably submits itself and each other Restricted Person to the non-exclusive jurisdiction of the state and federal courts sitting in the State of Utah and agrees and consents that service of process may be made upon it or any Restricted Person in any legal proceeding relating to the Amendment Documents or the Obligations by any means allowed under Utah or federal law.

Section 6.5. COUNTERPARTS. This Amendment may be separately executed in any number of counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment may be validly executed and delivered by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER US LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

QUESTAR MARKET RESOURCES, INC.
US Borrower

By: /s/ G. L. Nordloh

G. L. Nordloh
President and Chief Executive Officer

Mailing Address:
P.O. Box 45433
Salt Lake City, Utah 84145
Attention: Martin H. Craven

Street Address:
180 East 100 South
Salt Lake City, Utah 84111
Telephone: (801) 324-5497
Fax: (801) 324-5483

BANK OF AMERICA, N.A.
Administrative Agent, US LC Issuer and Lender

By: /s/ Tracey S. Barclay

Tracey S. Barclay
Principal

TORONTO DOMINION (TEXAS), INC.
Lender

By: /s/ Cank A. Clause

Cank A. Clause
Vice President

BANK OF MONTREAL
Lender

By: /s/ James Whitmore

James Whitmore
Director

BANK ONE, NA (MAIN OFFICE CHICAGO)
Lender

By: /s/ Sean Drinan

Sean Drinan
Vice President

FIRST SECURITY BANK, N.A.
Lender

By: /s/ Troy S. Akagi

Troy S. Akagi
Vice President

MELLON BANK, N.A.
Lender

By: /s/ Roger E. Howard

Roger E. Howard
Vice President

U.S. BANK NATIONAL ASSOCIATION
Lender

By: /s/ Mark E. Thompson

Mark E. Thompson
Vice President

THE BANK OF TOKYO-MITSUBISHI, LTD.,
HOUSTON AGENCY

Lender

By: /s/ K. Glasscock

K. Glasscock
Vice President and Manager

THE INDUSTRIAL BANK OF JAPAN, LIMITED
Lender

By: /s/ Michael C. Jones

Michael C. Jones
Vice President

SUMITOMO MITSUI BANKING CORPORATION,
formerly known as The Sumitomo Bank, Limited
Lender

By: /s/ Bob Grenfelt

Bob Grenfelt
Vice President and Manager

EXHIBIT 12

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

Year Ended December 31, -------------------------
------------------------- 2001 2000 1999 ---------

(Dollars In Thousands) EARNINGS Income before
income taxes $155,352 $ 116,426 $ 61,371 Less
income, plus loss from Canyon Creek (288) (162)
(231) Plus distributions from Canyon Creek 252
304 297 Less income from Roden (213) (290) Plus
distributions from Roden 301 355 Plus debt
expense 22,872 22,922 17,363 Plus interest
portion of rental expense 1,112 985 855 ---------

$179,388 $ 140,540 $ 79,655
==
FIXED CHARGES Debt expense $ 22,872 $ 22,922 $
17,363 Plus interest portion of rental expense
1,112 985 855 -----------------------------------
--------------- $ 23,984 $ 23,907 $ 18,218
==
Ratio of Earnings to Fixed Charges 7.48 5.88 4.37

For purposes of this presentation, earnings represent income before income taxes and fixed charges. Fixed charges consist of total interest charges, amortization of debt issuance costs, and the interest portion of rental costs estimated at 50%. Income before income taxes includes QMR's 50% share of pretax earnings of Blacks Fork. Distributions from less than 50% owned are included in the calculation, while earnings are from these same enterprises are excluded.

Exhibit 21

SUBSIDIARY INFORMATION

Registrant Questar Market Resources, Inc., has the following subsidiaries; Wexpro Company, Questar Exploration and Production Company, Questar Energy Trading Company, Questar Gas Management Company, and Shenandoah Energy, Inc. Questar Exploration and Production is a Texas corporation, and Shenandoah is a Delaware corporation. The other listed companies are incorporated in Utah.

Questar Exploration and Production has a wholly owned subsidiary, Celsius Energy Resources, Ltd., which is an Alberta corporation.

Questar Exploration and Production has one domestic active subsidiary: Questar URC Company, which is a Delaware corporation. Questar Exploration and Production also does business under the names Universal Resources Corporation, Questar Energy Company and URC Corporation.

Questar Energy Trading Company has two active subsidiaries: URC Canyon Creek Compression Company and Questar Power Generation Company, which are both Utah corporations.

Shenandoah, in turn has two active subsidiaries: SEI Drilling Company and SEI Gathering and SEI Gathering and Processing Company, which are both Colorado corporations.

EXHIBIT 23.

Consent of Independent Auditors

We consent to the incorporation by reference in the Registration Statement (Form S-4 No. 333-83254) of Questar Market Resources, Inc. and in the related Prospectus of our report dated February 8, 2002, with respect to the financial statements and schedule of Questar Market Resources, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2001.

/S/ Ernst & Young, LLP

Ernst & Young, LLP

Salt Lake City, Utah
March 25, 2002

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of Questar Market Resources, Inc., hereby severally constitute G. L. Nordloh and S. E. Parks, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2001 and any and all amendments to be filed with the Securities and Exchange Commission by Questar Market Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2001 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

SIGNATURE TITLE DATE --- ------ - ---- --- - /s/ R. D. Cash Chairman of the Board 2/9/02 - -------- -------- -------- --- R. D. Cash /s/ K. O. Rattie Vice Chairman 2/9/02 - -------- -------- -------- --- K. O. Rattie /s/ G. L. Nordloh President & Chief 2/9/02 - -------- -------- -------- --- Executive Officer G. L. Nordloh Director /s/ T. Beck Director 2/9/02 - -------- -------- -------- --- T. Beck /s/ P. J. Early Director 2/9/02 - -------- -------- -------- --- P. J. Early /s/ James A. Harmon Director 2/9/02 - -------- --------

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James A.
Harmon